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September 19, 2019

VIA ELECTRONIC FILING

The Honorable Jocelyn G. Boyd
Chief Clerk/Administrator
Public Service Commission of South Carolina
101 Executive Center Drive, Suite 100
Columbia, South Carolina 29210

RE: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)

South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)

Docket Nos. 2019-185-E and 2019-186-E

Dear Ms. Boyd,

Please find enclosed for filing in the above-captioned proceedings the *Amended Direct Testimony and Exhibits of Brendan Kirby*, filed by the Southern Alliance for Clean Energy ("SACE") and South Carolina Coastal Conservation League ("CCL"). The original testimony and exhibits of Mr. Kirby were filed on September 11, 2019.

The amended filings include the following corrections to the Direct Testimony of Brendan Kirby:

- on page 6, line 4, the word "larger" was corrected to "large";
- on page 11, footnote 7, the reference to "BAL-00201" was corrected to "BAL-002-1";
- on page 17, lines 1-2, the sentence "Idaho Power's solar integration study costs dropped from $2.50/MWH in 2014 to $0.85/MWH in 2016 for 700 MW of solar generation" was corrected to "Idaho Power's solar integration study costs

dropped from $2.50/MWH in 2014 for 700 MW to $0.85/MWH in 2016 for 1600 MW of solar generation.";
- on page 28, line 3, the word "change" was corrected to "chance";
- and on page 35, line 13, the word "ration" was corrected to "ratio".

The amended filings include the following corrections to Exhibit A of the Direct Testimony of Brendan Kirby:

- in Figure 2 on page 8, the reference to footnote 12 was corrected to reference footnote 13;
- and on page 13, footnote 25, the following phrase was deleted: "CAISO reports hourly ancillary service prices with monthly downloads available."

Enclosed is a Certificate of Service showing that all parties of record have been served with the amended testimony and exhibits. Please contact me if you have any questions concerning this filing or require anything else on this matter.

Sincerely,

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CERTIFICATE OF SERVICE

I hereby certify that the parties listed below have been served via electronic mail with a copy of the *Amended Direct Testimony and Exhibits of Brendan Kirby* filed on behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

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This 19th day of September, 2019.

s/ Lauren Fry
Lauren Fry

STATE OF SOUTH CAROLINA

BEFORE THE PUBLIC SERVICE COMMISSION

DOCKET NOS. 2019-185-E, 2019-186-E

In the Matter of South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A), and South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Progress, LLC's Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) - S.C. Code Ann. Section 58-41-20(A)	)	DIRECT TESTIMONY OF BRENDAN KIRBY ON BEHALF OF SOUTH CAROLINA COASTAL CONSERVATION LEAGUE AND SOUTHERN ALLIANCE FOR CLEAN ENERGY

I. INTRODUCTION AND QUALIFICATIONS

Q Please state your name, position, and business address for the record.

A Brendan Kirby, P.E., Consultant, 12011 SW Pineapple Court, Palm City, Florida, 34990.

Q Please summarize your professional and educational qualifications.

A I am currently a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), over fifteen utilities, the Energy Systems Integration Group (ESIG), Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory (ORNL), and others. I retired from the Oak Ridge National Laboratory's Power Systems Research Program.

I have 44 years of electric utility experience, and I have been working on electric power industry restructuring and ancillary services since 1994 and spot retail power markets since 1985.

I am a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.

A copy of my curriculum vitae is attached to my Expert Report as Appendix B.

Q Have you previously filed testimony as an expert witness in a regulatory proceeding?

A Yes. I have filed testimony in proceedings regarding wind and solar integration, bulk power system reliability, ancillary services, and demand response before Commissions in North Carolina, Georgia, California, Minnesota, Texas, Wyoming, and

Hawaii, as well as before the Federal Energy Regulatory Commission. I was appointed as the Special Advisor for Demand Response for the Hawaii Commission in 2015.

Q On whose behalf are you testifying in this proceeding?

A The South Carolina Coastal Conservation League ("CCL") and the Southern Alliance for Clean Energy ("SACE").

Q Are you sponsoring any exhibits?

A Yes, an Expert Report titled "Analysis of Duke Energy's Proposed Solar Integration Charge," included as Exhibit A.

Q What is the purpose of your direct testimony in this proceeding?

A The purpose of my direct testimony in this proceeding is to review and evaluate Duke Energy's proposed Solar Integration Services Charge ("SISC"). I discuss why the methodology used to develop the proposed SISC is fundamentally flawed, and as a result, the SISC is unsupported, inappropriate, and should be rejected by the Commission.

II. OVERVIEW OF DUKE ENERGY'S PROPOSED SOLAR INTEGRATION SERVICES CHARGE AND CONCLUSIONS

Q Please provide a brief overview of Duke Energy's proposed solar integration services charge.

A Duke Energy's proposed Solar Integration Services Charge is based on the DEC and DEP Ancillary Service Study performed by Astrapé Consulting ("*Ancillary Service*

Study" or "*Study*") that sought to compare production cost simulations with and without solar, while adjusting reserves in order to maintain reliability.[1]

Unfortunately, the *Ancillary Service Study* methodology has four fundamental flaws. First, it relied on a manufactured metric that does not accurately reflect the actual reliability standards the utility must meet in its day-to-day operations. The *Study's* "$\text{LOLE}_{\text{FLEX}}$" metric used a one-in-ten-years reliability limit that results in calculating excessive and unrealistic increased reserve requirements. This resulted in an unreasonably high integration charge. Second, the *Study* improperly scaled solar plant intra-hour output variability, also resulting in the calculation of excessive reserve requirements and charge. Third, the *Study* imposed the higher reserve requirements 8760 hours per year instead of limiting increased reserve requirements to times and conditions when increased solar generation might cause reserve shortfalls. Fourth, the *Study* required the added reserves to come from online, spinning generation rather than allowing lower cost non-spinning resources to provide some or all of the added reserves, greatly increasing the cost of supplying additional reserves. Each of these methodological errors led to an unreasonable and excessive SISC. Compounding these flaws is the fact that the study methodology has not undergone independent peer review or a technical review committee that could help further vet the proposed approach and findings.

Furthermore, the predictions generated by the *Ancillary Service Study* do not reflect actual operations in South Carolina. The limited historical operating reserve data provided by DEC and DEP demonstrates that increasing solar penetration is not well correlated with increased operating reserves data. Similarly, data from other jurisdictions

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[1] Direct Testimony of Nick Wintermantel on Behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Exhibit 2 (hereinafter "Wintermantel Direct Testimony") Docket Nos. 2019-185-E and 2019-186-E (filed copy of *Ancillary Service Study*).

with high levels of renewable penetration indicates that increased renewable penetration does not substantially increase operating reserve requirements.

Q Have you reviewed Duke Energy's witness testimony regarding the proposed solar integration services charge?

A Yes, I reviewed the Direct Testimony of Nick Wintermantel and Glen A. Snider, and the report Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study, November 2018 contained in Mr. Wintermantel's testimony.

Q What is your reaction to that testimony and Duke Energy's proposal?

A The basic premise that adding variable renewable generation to the power system may increase operating costs is not unreasonable. The analysis methodology of comparing production cost simulations with and without solar, while adjusting reserves in order to maintain reliability, is also sound. Unfortunately, the analysis *as implemented* is deeply flawed. As a result, the SISC developed by the *Ancillary Service Study* does not reflect actual increased reserve requirements or actual impacts on the operating costs that Duke Energy will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements, capabilities, and operations.

Q Please provide an overview of the primary issues you have identified with the *Ancillary Service Study*.

A The report attached as Exhibit A details concerns with the *Ancillary Service Study* and the resulting SISC. There are several serious concerns with the analysis method.

First, the *Study* modeled DEC and DEP as physically isolated power systems rather than modeling DEC and DEP as physically interconnected utilities. In reality, DEC and DEP are physically connected to and part of the Eastern Interconnection, and this physical interconnection impacts the real-world reliability standards the Companies must meet, and should thus be reflected in their modeling. The Eastern Interconnection is the large electricity grid that includes both DEC and DEP, and being part of the Eastern Interconnection allows DEC and DEP to operate less stringently than if they were physically islanded electricity systems. Astrapé's use of an arbitrary and overly stringent loss-of-load, one-in-ten-years $LOLE_{FLEX}$ metric does not reflect Duke Energy's actual operations, including the benefits of being part of the Eastern Interconnection, and is inappropriate for this type of modeling.

Second, the *Study* improperly scaled solar plant intra-hour variability data in a way that fails to accurately reflect the geographic diversity benefits of solar power that is physically distributed across the electricity grid.

Third, the *Study* failed to identify the specific operating conditions under which reliability was challenged and instead increased operating reserve requirements during all hours, even overnight when solar generation cannot possibly add variability or uncertainty to the system. The *Study* failed to identify the specific added reserve requirements or changes in operating practices actually needed to cost effectively maintain reliability.

Fourth, the *Study* forced all added solar integration reserves to come from online spinning generation rather than allowing some or all reserves to come from much lower cost non-spinning, off-line, fast start generation and demand response, greatly increasing solar integration costs.

Q Is this the first time that Duke Energy has proposed a Solar Integration Services Charge for renewable qualifying facilities?

A No. Duke Energy has proposed an identical Solar Integration Services Charge in the current North Carolina Utilities Commission biennial avoided cost proceeding in Docket No. E-100 Sub 158.

Q Did you evaluate the *Ancillary Service Study* in the North Carolina proceeding?

A Yes, I reviewed and assessed the *Ancillary Service Study* in North Carolina and prepared a report addressing many of the same analytical and methodological flaws that I have discussed above in this testimony. I testified before the North Carolina Utilities Commission at its hearing in July 2019 on this matter, and my understanding is that a decision is pending before that Commission.

Q Are your findings regarding the *Ancillary Service Study* in the North Carolina proceeding applicable in this proceeding?

A Yes. Because Duke Energy applied the identical study and has proposed the identical SISC, my analysis in the North Carolina proceeding is equally applicable in this proceeding. My report for South Carolina has been updated based upon additional information and explanations Duke Energy provided in response to the filing of my report in North Carolina.

III. <u>ACCURACY OF THE *ANCILLARY SERVICE STUDY'S* PREDICTIONS</u>

Q Has Duke Energy verified that the *Ancillary Service Study* calculates reserve requirements that are consistent with the historic data?

A No. While Page 17 of Wintermantel's Direct Testimony stated that "[a]nalysis was performed that showed historical realized operating reserves compared well with the modeled operating reserves reported from the SERVM simulations that resulted in a 0.1 $\text{LOLE}_{\text{FLEX}}$" Duke Energy in fact made little or no attempt to verify that the reserve requirements calculated based on the $\text{LOLE}_{\text{FLEX}}$ metric matched historic operating experience until the North Carolina Utilities Commission requested historic operating reserve data during an evidentiary hearing.

Q Does the historical operating data Duke Energy provided in response to the North Carolina Utilities Commission and SACE DR 1-20 and 1-21 demonstrate that the *Ancillary Service Study's* predicted reserve requirements are consistent with historical data?

A No. First, Duke Energy did not provide the data necessary to verify the *Ancillary Service Study's* predictions. Though requested by the North Carolina Utilities Commission, and again by SACE and CCL in Data Requests 1-20 and 1-21 in this proceeding, Duke Energy declined to provide historical data supporting the *Ancillary Service Study's* predictions. Duke Energy declined to provide data from before 2015 citing the inconvenience of accessing historic records.[2] Duke Energy also declined to "re-run" the *Ancillary Service Study* and compare its predictions to the solar penetration and weather conditions actually experienced in 2015 through 2018. Instead, Duke Energy provided only annual average results previously calculated for lower and higher solar penetrations.

[2] Duke's response to SACE and CCL's Data Requests 1-20 and 1-21 states "data for years preceding deployment of the TGIS energy accounting database (i.e. prior to 2015) is maintained in archived historical data formats for DEC and DEP and is not readily available. An additional 60 business days would be required to manually retrieve, process and validate archived 2010 - 2014 data." DEC DEP SC Response to SACE CCL DR 1-20, Docket Nos. 2019-185-E and 2019-186-E, Exhibit B; DEC DEP SC Response to SACE CCL DR 1-21, Docket Nos. 2019-185-E and 2019-186-E, Exhibit C.

Furthermore, rather than examining hourly results to see how the *Study's* predictions compared to historical data, Duke Energy provided only annual averages and said that "[i]n general, the analysis presented below shows that the 60-minute ramping capability in Astrapé's 'no solar' scenario, which results in 0.1 LOLEflex, is in line with the Companies' actual historical, realized operating reserves."[3] Even this limited endorsement is overstated based on an examination of the actual modeled and historic reserves as shown below. This is hardly the verification that one would expect for a new modeling method and metric and the imposition of significant costs on solar facilities through the proposed SISC.

Q Can any conclusions regarding the accuracy of the *Ancillary Service Study's* predictions be drawn based on the historical data Duke Energy has provided?

Yes, the historical data demonstrated that the *Ancillary Service Study's* predictions are not accurate. However, because Duke Energy did not provide sufficiently granular operating reserves data, it is difficult to determine exactly how far off the *Study's* predictions are from actual operations.

Figure 1 compares the annual average historic operating reserves and the modeled reserves reported in SACE CCL DR 1-20 and 1-21 versus solar penetration based on data from 2015 through 2018 if one assumes that the same categories of reserves are included in the historical operating reserves and the *Ancillary Service Study's* predictions. Figure 1 shows that Duke Energy's claim that the "historical realized operating reserves compared well with the modeled operating reserves" is inaccurate.

[3] DEC DEP SC Response to SACE CCL DR 1-20, Docket Nos. 2019-185-E and 2019-186-E, Exhibit B; DEC DEP SC Response to SACE CCL DR 1-21, Docket Nos. 2019-185-E and 2019-186-E, Exhibit C.

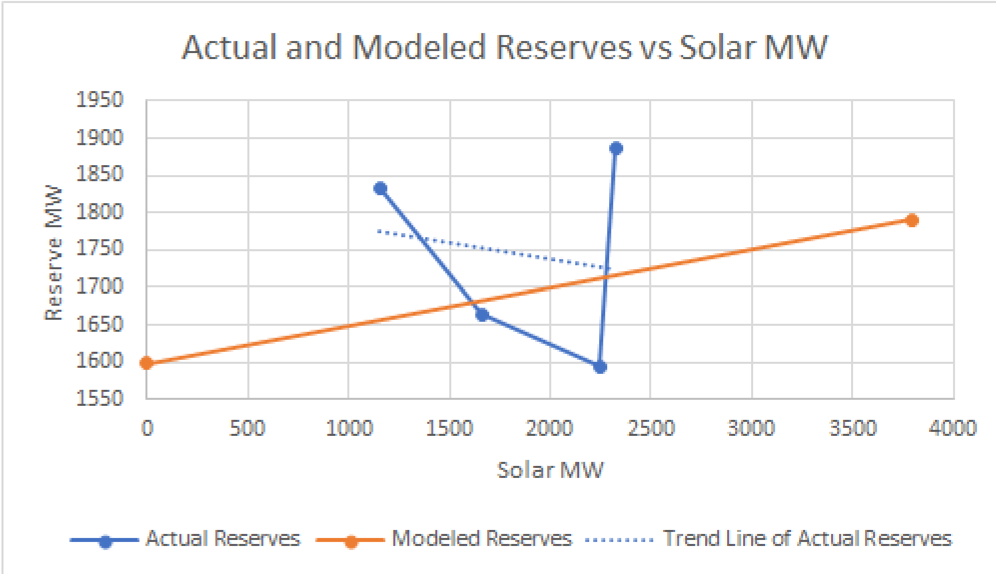

Figure 1: Historical Actual Reserves v. Ancillary Service Study Predictions[4]

Utilities typically hold a significant fraction of their contingency reserves as spinning reserves, often half.[5] If DEC and DEP were operating with 400 MW of spinning reserve held for contingencies, then Figure 2 would more accurately depict the relationship between the Ancillary Service Model's predictions and actual historical reserves.

[4] DEC and DEP Joint Initial Statement, p. 7, Fig. 1, illustrates the cumulative installed solar capacity in DEC and DEP territory for the years 2014-2018. Using this data, we can determine the Reserve MW that have historically been maintained at various levels of installed solar capacity.

[5] While Duke failed to report on the breakdown of spinning and non-spinning contingency reserves, Duke's response to SACE CCL Data Request 1-20 and 1-21 states that "DEP maintains most of its contingency reserves off-line" indicating that some of DEP's and most of DEC's contingency reserves are spinning reserves.

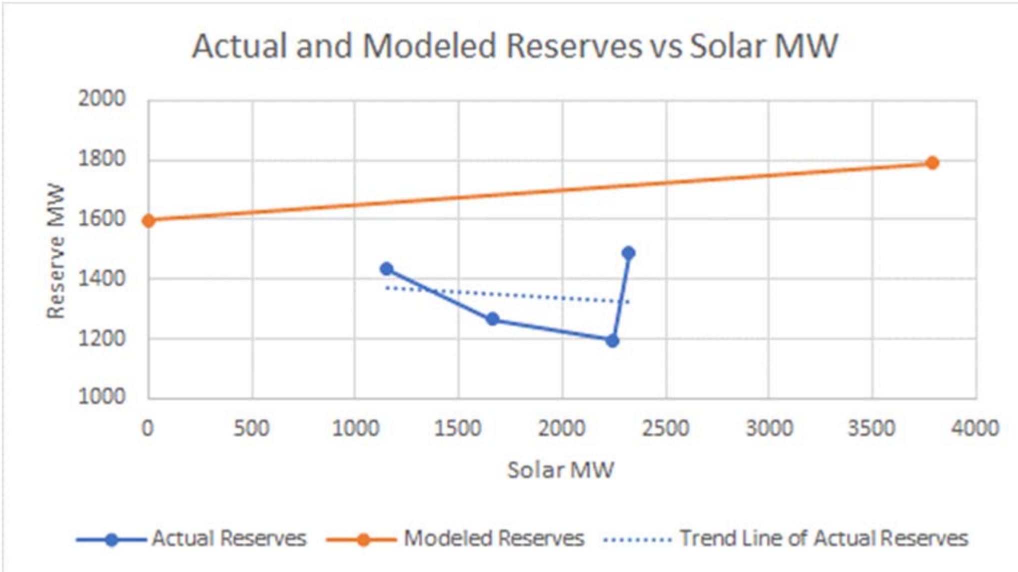

Figure 2: Historical Actual Reserves Assuming 400 MW of Spinning Contingency Reserves v. Ancillary Services Study Predictions.[6]

It is impossible to ascertain which of these comparisons is more accurate because Duke Energy also failed to follow the North Carolina Commission directive to provide a sufficiently granular breakdown of reserves, listing the spinning and non-spinning contingency reserves, despite being obligated by NERC rules to maintain records of reserves for at least three of the four historical years being analyzed.[7] Regardless, the information provided by Duke does not verify the *Ancillary Service Study's* predictions or results.

[6] Lacking a specific reply from Duke 400 MW, or a little less than half, of the DEC DEP contingency reserves are assumed to be spinning, which is typical for many utilities.

[7] *See* NERC standard BAL-002-0, R3.1 – Disturbance Control Performance required: "As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." BAL-002-1 was in effective until BAL-002-2 became effective in October 2017. Duke should have NERC auditable records documenting compliance with BAL-002-1 that list the specific generating units and their MW spinning and non-spinning reserve capabilities that were supplying the required contingency reserves for each hour.

Q DEC and DEP solar generation has increased significantly from 2015 to the present. Does the historic record show that reserve requirements have been rising as solar penetration increases?

A No. While the *Ancillary Service Study* stated that "load following additions … increase exponentially as more solar is added to the system"[8] Figure 3 shows that actual operating reserves did not increase significantly while solar generation doubled from 2015 to 2018.

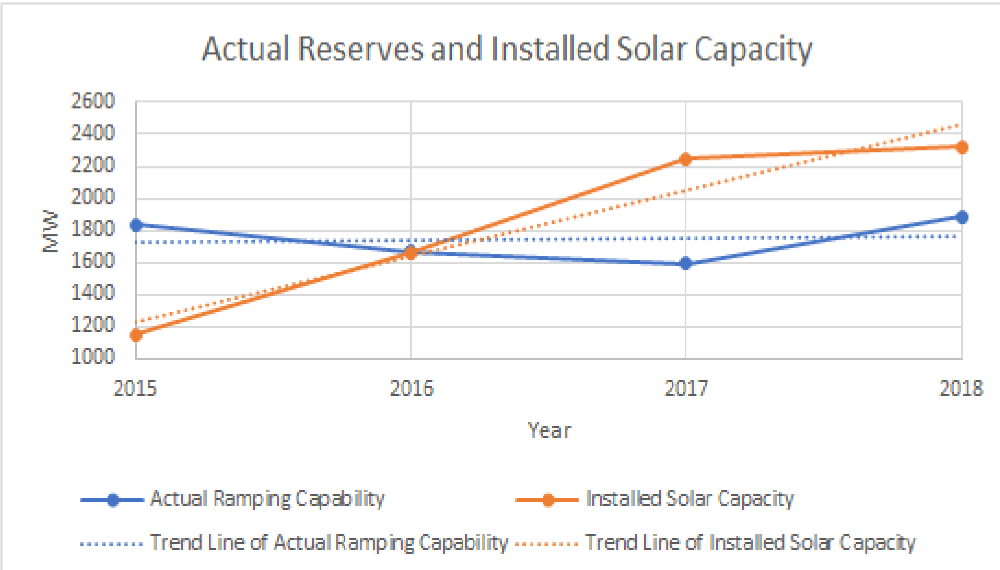

Figure 3: Historical Actual Reserves v. Installed Solar Capacity[9]

[8] Ancillary Service Study at p. 47.
[9] Source: DEC and DEP Joint Initial Statement p. 7, Fig. 1; DEC DEP SC Response to SACE CCL DR 1-20, Docket Nos. 2019-185-E and 2019-186-E, Exhibit B; DEC DEP SC Response to SACE CCL DR 1-21, Docket Nos. 2019-185-E and 2019-186-E, Exhibit C.

IV. TRENDS IN SOLAR INTEGRATION COSTS FROM OTHER JURISDICTIONS

Q Are other high solar and wind penetration regions experiencing high integration reserve requirements and costs?

A No. Utilities with high variable generation penetration have found that reserve requirements and costs do not rise "exponentially." Geographic aggregation benefits of solar and wind greatly reduce the actual variability and uncertainty of integrating these resources. Utility operators have typically been able to manage solar and wind variability and uncertainty without dramatically increasing reserve requirements or costs.[10]

Q California has higher solar penetration than the Carolinas, have operating reserve requirements increased there?

A No. Operating reserve amounts and costs have not increased for the California Independent System Operator (CAISO) while they have integrated 20,000 MW of solar generation and 6,700 MW of wind generation.[11] CAISO solar and wind penetration is 56% of peak load compared with 5% to 33% penetration analyzed in Duke Energy's *Ancillary Service Study*.

The blue dotted curve in Figure 4 shows that the total operating reserve amounts procured by the CAISO from 1999 through 2018 have remained relatively constant over

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[10] These issues were discussed extensively in the North Carolina Avoided Cost Proceeding by NCSEA Witness Thomas Beach. Direct Testimony of R. Thomas Beach on behalf of NCSEA, Docket No. E-100, Sub 158, *available at* https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=b2e29d56-7f73-4adb-9ac0-224557f38bf8.

[11] *See* California ISO, What are we doing to green the grid? (Sept. 9, 2019) http://www.caiso.com/informed/Pages/CleanGrid/default.aspx;
California ISO, Reports and bulletins keep you current, (last accessed Sept. 9, 2019) http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx .

the years.[12] The other dotted curves show each of the individual reserves (regulation down, regulation up, spinning reserve, and non-spinning reserve). Reserve requirements certainly have not increased dramatically as solar and wind generation has increased, as shown by the solid green curve.

Reserve requirements do vary from time to time as NERC rules change. For example, contingency reserve requirements increased in 2018 (visible at the far right of the graph) because the largest credible contingency was increased to include loss of both halves of the Pacific DC Intertie, a larger contingency than had previously been planned for. Interestingly, CAISO increased the amount of regulation it procured in early 2016 due to concerns about the amount of wind and solar generation on the system. After a few months CAISO found that it did not need the additional reserves.

CAISO has found, through actual operating experience, that they do not require "exponentially increasing" amounts of operating reserves to integrate much larger amounts of solar generation than DEC and DEP are expecting.

[12] California ISO, Annual Report(s) on Market Issues and Performance, 2005 through 2018, http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

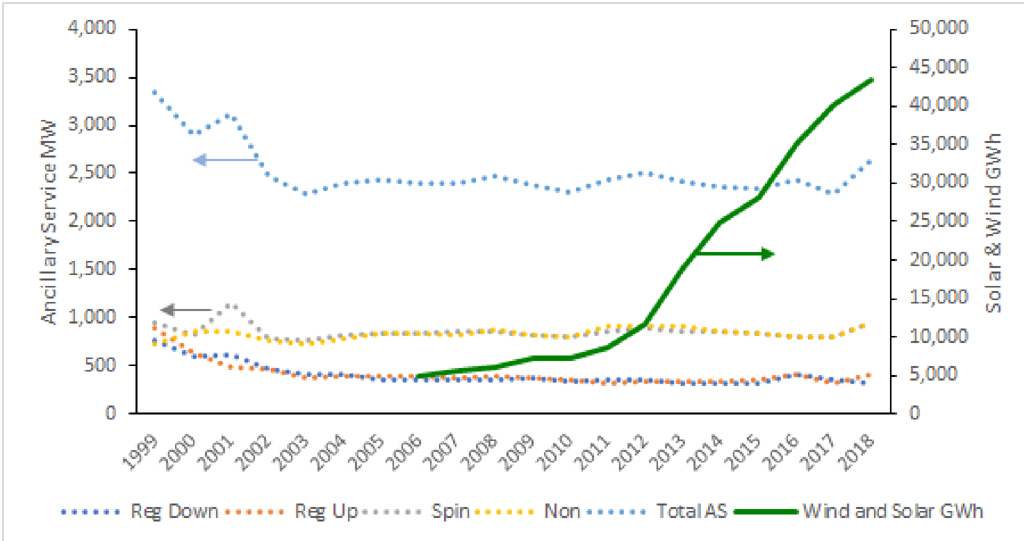

Figure 4: CAISO Operating Reserves have not increased with increasing solar and wind penetration.

Q Have operating reserve costs increased for CAISO as solar and wind penetration have increased?

A No. Figure 5 shows that operating reserve costs have not increased as solar and wind have increased 900% between 2006 and 2018. The green line in Figure 5 shows the dramatic increase in solar and wind generation. The red line shows the ancillary service cost (as a percentage of wholesale energy cost). Interestingly, variations in ancillary service costs are strongly influenced by the annual amount of available hydro generation, but they clearly have not risen as wind and solar generation increased to supplying over 19% of CAISO energy requirements.[13]

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[13] Ancillary service prices drop in CAISO in low water years when hydro plants are not continuously occupied moving water and producing energy.

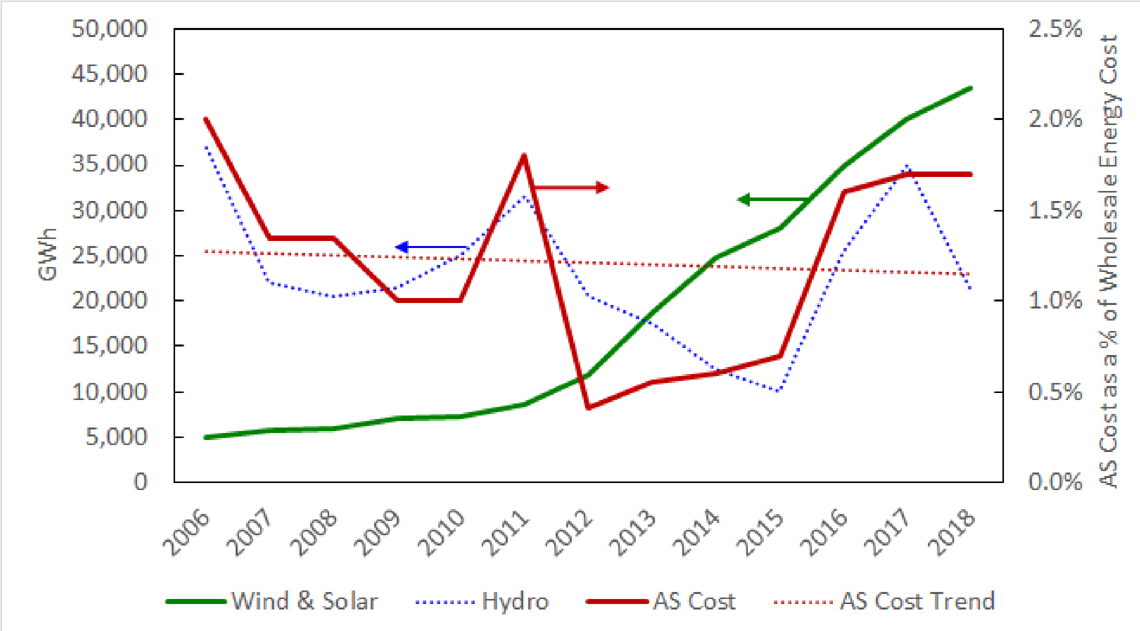

Figure 5: Operating reserve costs have not risen in California with increasing solar and wind penetration.[14]

Q Are there other examples showing that solar integration costs tend not to increase as utilities gain actual operating experience with higher solar and wind penetrations?

A Yes. The California Public Utilities Commission began a process to develop wind and solar integration charges, but it has not seen the need to complete that process and permanently adopt such charges.[15]

PacifiCorp's wind integration study cost declined from \$3.06/MWH in 2014 with 2,543 MW of wind to \$0.44/MWH in 2017 with 2,793 MW of wind.[16]

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[14] CAISO 2006-2018 Annual Report(s) on Market Issues and Performance, http://www.caiso.com/market/Pages/MarketMonitoring/AnnualQuarterlyReports/Default.aspx.

[15] The California commission has had a series of rulemaking proceedings to administer the state's Renewable Portfolio Standard ("RPS") program. The rulemaking initiated in 2015 (R. 15-02-020) included as an issue the continuing development of integration cost adders (see R. 15-02-020, at p. 6), but this issue was dropped in the next RPS rulemaking initiated in 2018 (R. 18-07-003).

[16] PacifiCorp's 2015 Integrated Resource Plan (IRP), at Appendix H, Table H.3. PacifiCorp's 2017 IRP, Volume II, at Appendix F, pp. 120-23, Tables F.14 and F.16.

Idaho Power's solar integration study costs dropped from $2.50/MWH in 2014 for 700 MW to $0.85/MWH in 2016 for 1600 MW of solar generation.[17]

In all three cases the utilities and state utility commissions learned through experience that integrating solar and wind generation is not as difficult or expensive as initially anticipated.

V. FLAWS IN THE *ANCILLARY SERVICE STUDY'S* METHODOLOGY

A. FLAWED RELIABILITY METRICS

Q Your report discusses NERC reliability requirements in some depth. Is this necessary?

A Yes. Closely approximating NERC mandatory reliability requirements is fundamental to correctly calculating the added reserve requirements imposed by integrating large amounts of solar generation and thus to calculating an accurate solar integration charge. Astrapé's newly proposed approach to using a "$\text{LOLE}_{\text{FLEX}}$" reliability criteria that is unrelated to the actual NERC reliability requirements or to the physical balancing requirements of a power system operating in the Eastern Interconnection does not accurately reflect DEC and DEP's actual balancing requirements. This approach vastly overstates the cost of integrating solar generation. A review of the NERC reliability standards and metrics shows that the Companies' actual balancing requirements are much less than those artificially imposed by Astrapé's modeling.

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[17] Idaho Power, Direct Testimony of Philip B. Devol, Idaho PUC Case No. IPCE-14-18 (July 1, 2014), at p. 5. Idaho Power, Solar Integration Study Report, (April 2016), at pp. vi and 21, Tables 2 and 9.

Q What is the link between the NERC reliability standards and a utility being a part of the Eastern Interconnection?

A As further explained in my report, the benefit of interconnecting utilities is that they all share in diversity and aggregation benefits of each other's systems. The Eastern Interconnection is much stronger and more reliable than any single utility system within it, and the Eastern Interconnection requires much less balancing response because it is interconnected. All interconnected utilities share in this reduced balancing requirement. The balancing requirement is not moved to another utility, it is genuinely reduced for all participants.

Q Has NERC ever had a standalone balancing requirement?

A Yes, NERC established the A1-A2 Control Performance Policy in 1973.[18] A1 was a standalone balancing requirement that required each Balancing Authority (BA) to force its Area Control Error (ACE) to zero at least once every 10 minutes.[19,20] That meant that each BA had to balance its own generation and load every ten minutes regardless of conditions on the rest of the interconnection.

Q Does NERC still have a standalone balancing requirement?

A No, NERC replaced the A1 and A2 in 1996 with CPS1, CPS2, and DCS. As discussed in my report, CPS2 was itself replaced with the BAAL criteria in 2016.

Q Why did NERC abandon the A1 standalone balancing requirement?

A NERC recognized that the A1 requirement for standalone balancing every 10 minutes was not technically justified and was incorrectly independent of interconnection

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[18] BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, North American Electric Reliability Corporation, February 2013

[19] Imports and exports were also allowed. The small frequency bias term also had to be included.

[20] A2 required that the average ACE for each 10-minute interval had to be within limits and is a much laxer requirement than $LOLE_{FLEX}$ or A1.

frequency. NERC found that the apparently very common-sense concept that requiring every BA to balance their system every ten minutes actually hurt power system reliability. Consequently, a laxer balancing standard that improves power system reliability was adopted. It also lowers cost.

Q How can forcing standalone balancing hurt power system reliability?

A When power system frequency is below 60 hz there is less generation output within the overall Eastern Interconnection than there is load, at that instant. If a BA happens to be over-generating at that time, it hurts overall power system reliability if that BA reduces generation, at that instant, simply to comply with the A1 requirement of forcing ACE to zero every ten minutes. As discussed in my report, the current BAAL requirement does not require a BA to correct an imbalance if that imbalance is helping to push the Eastern Interconnection frequency back to 60 hz. It also allows gives a BA 30 minutes to correct an imbalance that is harming interconnection frequency.

Q How is this relevant to calculating the DEP and DEC solar integration services charge?

A An understanding of the actual mandatory NERC balancing requirements shows why the $LOLE_{FLEX}$ balancing requirement is overly burdensome and unrelated to actual power system operations. $LOLO_{FLEX}$ is similar to the old A1 requirement, but even more stringent. Astrapé's $LOLE_{FLEX}$ metric as used in the study for this proceeding requires balancing every 5 minutes, while A1 required balancing only every 10 minutes. As described above, NERC found that A1 was unnecessary and actually harmed interconnection reliability because it did not consider interconnection frequency.[21] An

[21] BAL-001-2 – Real Power Balancing Control Performance Standard Background Document, North American Electric Reliability Corporation, February 2013

analysis that is more closely related to the actual current NERC 30-minute BAAL requirement will calculate a more accurate solar integration charge.

Q Your report also discusses the NERC Disturbance Control Standard. How are reliability requirements related to the sudden failure of large conventional generators relevant to calculating the DEP and DEC solar integration services charge?

A NERC's requirements for responding to the instantaneous failure of a large generator are relevant to solar integration reliability requirements for two reasons. The first reason concerns the required response speed. The instantaneous failure of a 1,000 MW conventional generator, for example, is a much greater reliability event than any solar generation variation. NERC requires full balancing response to even the largest disturbance within 15 minutes, not the 5 minutes required by $\text{LOLE}_{\text{FLEX}}$.[22]

Equally important, much lower cost non-spinning reserves that can fully respond within 15 minutes are often used to respond to major contingencies like the instantaneous failure of a 1,000 MW generator rather than requiring all balancing reserves to come from expensive, online spinning reserves.[23] Non-spinning reserves are used to meet Disturbance Control Standard requirements because they are much lower cost than spinning reserves: 15% of the cost of spinning reserve in PJM's Mid-Atlantic Dominion region.[24] Duke states "DEP maintains most of its contingency reserves off-line."[25] There

[22] The even slower 30-minute response required by BAAL actually applies to solar imbalance events.
[23] Disturbance Control Standard reserve requirements for DEC and DEP are set by SERC Reliability Corporation, the Regional Reliability Council for South Carolina, North Carolina, Florida, Georgia, Alabama, Mississippi, Louisiana, Tennessee, and parts of Texas, Oklahoma, Arkansas, Missouri, Iowa, Illinois, Kentucky, and Virginia.
[24] PJM's Mid-Atlantic Dominion region is the geographically closest area to DEC and DEP with publicly available spinning and non-spinning hourly prices. Data downloaded for all of 2018 from http://dataminer2.pjm.com/list.

is no technical reason for requiring solar integration reserves to come exclusively from expensive spinning reserves when non-spinning reserves are much lower cost and routinely used to respond to the more challenging contingency events.

More expensive spinning reserves should only be utilized for frequent imbalances, not for contingencies or $LOLE_{FLEX}$ events which the *Ancillary Service Study* says “rarely occur”.[26]

Q Is it difficult to perform the analysis with balancing requirements that are more closely aligned with the mandatory NERC reliability requirements?

A No. The analysis of balancing requirements simply needs to recognize that NERC does not require perfect balancing and to select a metric that more closely reflects the actual needs. As discussed in my report, it is not possible to simply “plug in” the NERC requirements because NERC recognizes that each BA is operating within the Eastern Interconnection. Actual reliable operations, therefore, depend in real-time on the conditions throughout the Eastern Interconnection. That does not mean that analysis can’t be performed. It simply means that the analysis must reflect how the actual power system operates. Perfect balancing is neither possible nor desired.

Q Mr. Wintermantel stated that the model “has perfect foresight” of the 5-minute ahead load and that this makes it easier for the model to balance the power system than actual operations where “operators do not have perfect foresight and are constantly chasing net load.”[27] Mr. Wintermantel also stated that “[b]ecause of this perfect foresight and because of other operational challenges that cannot be

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[25] DEC DEP SC Response to SACE CCL DR 1-20, Docket Nos. 2019-185-E and 2019-186-E, Exhibit B; DEC DEP SC Response to SACE CCL DR 1-21, Docket Nos. 2019-185-E and 2019-186-E, Exhibit C.
[26] *Ancillary Service Study* at p. 11.
[27] Wintermantel Direct Testimony at p. 10.

modeled, it is expected that $\mathrm{LOLE}_{\mathrm{FLEX}}$ events within SERVM will always be less frequent than a Balancing Authority's NERC frequency imbalances."[28] Is it correct to say that the *Ancillary Service Study* methodology 1-event-in-10-years $\mathrm{LOLE}_{\mathrm{FLEX}}$ 5-minute balancing metric is less restrictive than actual NERC reliability requirements?

A No. NERC's CPS1 balancing requirement limits the *one-year* balancing deviations. NERC's BAAL balancing requirement only applies to balancing deviations that last over 30 minutes and that are hurting interconnection frequency. The problem with the 0.1 $\mathrm{LOLE}_{\mathrm{FLEX}}$ metric is that the "event" the model is looking for—one failure of the system to follow net load given 5-minute ahead perfect foresight—does not actually result in a loss of load or a NERC reliability standard violation. NERC has no balancing requirements that apply in the 5-minute time frame. This means that even if the *Ancillary Service Study's* "perfect foresight" assumption leads to a relatively low number of "events" being identified, the addition of reserves to respond to these events and return system reliability to 0.1 $\mathrm{LOLE}_{\mathrm{FLEX}}$ still significantly overstates the amount of reserves necessary to conform to NERC balancing standards.

Q What are the consequences of using the inappropriate $\mathrm{LOLE}_{\mathrm{FLEX}}$ reliability metric rather than one based more closely on actual NERC reliability standards?

A The additional reserve requirements calculated to compensate for increased solar penetration are likely dramatically overstated.

[28] *Id.*

B. <u>LINEAR SCALING OF SOLAR DATA</u>

Q You discuss solar variability and uncertainty in your report at some length. Why is this necessary?

A The additional reserves required to maintain reliability when significant amounts of solar generation are added to a power system depend on the variability and uncertainty of the aggregated solar fleet, combined with the variability and uncertainty of the aggregate load. The *Ancillary Service Study* assumed that solar variability would scale linearly—variability would double if the amount of solar generation doubled.[29] This assumption ignores the geographic diversity of solar power facilities. A cloud that moves over a solar plant and reduces the output power does not simultaneously move over every solar plant. It takes time for a cloud shadow to move from one solar plant to another. Analyzing the historic solar data, I found that the short-term variability between multiple solar plants is highly uncorrelated. This means that the output from new solar plants will not be perfectly correlated with each other or with the output of existing solar plants, and the *Study* should fully account for this geographic diversity benefit of solar power.

Q Should solar variability be reexamined regularly as the solar fleet grows?

A Yes, actual solar output data should be analyzed regularly to determine how the characteristics of the solar fleet are changing, just as actual load data is regularly analyzed to assure that the aggregate load is being correctly modeled. When it is necessary to predict the behavior of a future solar fleet that includes solar plants that do not yet exist (for the assessment of potential solar integration costs, for example) it is more reasonable to assume that the short-term volatility of new solar plants will be largely uncorrelated with the short-term volatility of the existing solar fleet and with the

[29] A case with 75% variability was also analyzed.

short-term volatility of other new solar plants than it is to assume that the outputs of future solar plants will be perfectly correlated (linear scaling) with the short-term output of the existing solar fleet. Linear scaling overstates the amount of reserves that will be required to balance the growing solar generation fleet.

Q Duke Energy Witness Wintermantel states that Astrapé declined to include diversity benefits in the *Ancillary Service Study* because these benefits are too uncertain.[30] Do you agree with Witness Wintermantel?

A No. Witness Wintermantel's justification for ignoring the natural aggregation benefits that reduce solar variability as more solar generation is added is not compelling. Historic solar output data from Duke Energy's own power systems shows variability decreasing as the amount of solar generation increased. Witness Wintermantel's explanation for ignoring the diversity benefit explanation is speculative at best:

> "[W]hile it is expected there will be additional diversity within a potential future high penetration solar fleet, the fact that larger units are coming online may dampen the diversity benefit."[31]

The *Ancillary Service Study's* explanation is no more convincing:

> "Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while

[30] Wintermantel Direct Testimony pp. 20-21.
[31] Direct Testimony of Nick Wintermantel at p. 20.

it is expected there will be additional diversity among the solar fleet, the fact that larger units are coming on may dampen the diversity benefit."[32]

The fact that diversity benefits may change over time is no excuse for completely ignoring its value in calculating the SISC. Further, the *Ancillary Service Study* based its solar variability estimate on one year of data collected between October 2016 and September 2017. The solar fleet has grown considerably from the 244-431 MW that were operating during that test year. Actual solar variability of the current solar fleet can and should be determined.

Q What are the consequences of assuming there is no aggregation benefits as the solar fleet grows?

A The additional reserve requirements calculated to compensate for increased solar penetration are likely dramatically overstated.

C. <u>RELIANCE ON SPINNING RESERVES</u>

Q Does the *Ancillary Service Study* impose reserve requirements appropriately?

A No. In addition to inflating solar integration reserve requirements by using of the inappropriate $LOLE_{FLEX}$ metric and failing to recognize solar diversity benefits by linearly scaling solar variability, the *Study* also inappropriately inflated the cost of supplying additional solar integration reserves by excluded low-cost non-spinning reserves and only considered expensive spinning reserves for supply of solar integration reserves and additional reserve requirements. Furthermore, the *Study* imposed these additional reserve requirements 8760 hours per year, even during nighttime hours when no solar generation is possible.

[32] *Ancillary Service Study* at pp. 30-31.

Q NERC and SERC allow low cost non-spinning reserves to be used to respond to large generator failures but Duke only considered spinning reserve for solar integration. Is this appropriate?

A No. Requiring additional reserves for solar integration to come from online generation that is unloaded (spinning reserves) is unnecessary and needlessly expensive. NERC and SERC reliability rules allow Duke Energy to obtain contingency reserves from off-line, fast-start, non-spinning reserves. Contingencies are the instantaneous tripping of a large generator. They happen much faster than a solar ramp caused by moving clouds. NERC reliability rules require DEP and DEC to fully rebalance within 15 minutes of a contingency. DEP and DEC have 30 minutes to correct an imbalance caused by a solar ramp. Non-spinning reserves are an appropriate resource for solar integration, especially for infrequent reserve shortfalls identified by a 1-event-in-10-years reliability criteria.

Non-spinning reserves are much lower cost than spinning reserves. Regions with electricity markets like PJM, ERCOT, and CAISO publish hourly spinning and non-spinning costs. Non-spinning reserve costs are much lower than spinning reserve costs. PJM's Mid Atlantic Dominion region is the closest area to DEC and DEP with published spinning and non-spinning reserve costs. Non-spinning reserve costs averaged 15% of spinning reserve costs in the Mid-Atlantic Dominion region for 2018. If the cost difference is similar for DEC and DEP simply allowing solar integration reserves from non-spinning resources would reduce the DEC solar integration charge from $1.10/MWH to $0.17/MWH for the Existing Plus Transition level of solar penetration while the cost for DEP would reduce from $2.39/MWH to $0.36/MWH, even assuming no corrections to the amount of reserves required.

Q Did Duke explain why it requires all solar integration reserves to come from expensive online spinning generation?

A No. Duke Energy offered no explanation regarding why the *Ancillary Service Study* requires all solar integration reserves to come from online spinning reserves.

D. <u>UNIFORM DISTRIBUTION OF ADDED RESERVES</u>

Q Did the *Ancillary Service Study* add reserve requirements tailored to the times and conditions of increased solar variability and uncertainty?

A No. Rather than increasing reserve requirements only under conditions or during times when modeling showed that increased solar generation imposed a risk of a reserve shortfall the *Ancillary Service Study* methodology increased reserve requirements 8760 hours per year until the $LOLE_{FLEX}$ metric returned to a 1-event-in-10-year threshold.[33]

Q Why is it inappropriate to increase reserve requirements 8760 hours per year?

A Clearly, increased solar generation cannot increase reserve requirements during the night. There is no technical justification for imposing additional reserve requirements during times when solar generation does not increase the risk of reserve shortfalls. Solar generators should not be required to pay for the cost of holding increased reserves during times when they are not even operating.

[33] "In order to increase online operating reserves, the minimum load following target in MWs is increased in SERVM. This is applied uniformly in every hour." DEC DEP SC Response to SACE CCL DR 1-25, Docket Nos. 2019-185-E and 2019-186-E, Exhibit D.

Similarly, additional reserve requirements should only be imposed for conditions where modeling shows there is an increased risk of reserve shortfalls. For example, if modeling shows that there is an increased chance of a reserve shortfall only during summer evenings, when a specific conventional generator is out of service and when solar generation is ramping down but load is still increasing, then reserve requirements should be increased during times of those specific conditions. The cost of added reserves during those specific conditions may be fairly ascribed to solar facilities. However it is not appropriate to impose the cost of holding additional reserves at all times upon solar facilities which only operate during a subset of those times.

Q How does Duke Energy explain the *Ancillary Service Study's* decision to increase reserve requirements 8760 hours per year?

A In response to SACE CCL DR 1-25 Duke Energy sought to justify increasing the solar integration reserve requirements during all hours by stating: "**initial simulations** indicated that during off-peak and shoulder hours, there are excess reserves above the minimum target in the **base case** meaning the **increase in operating reserves is primarily during the higher net load hours**."[34]

Q Does Duke Energy's explanation for increasing reserve requirements 8760 hours per year satisfy you?

No. This is not a compelling response, for two reasons. First, Duke Energy admits that it is relying exclusively on "initial simulations" of exclusively the no-solar base case and that results "primarily" impact high net-load hours. Second, Duke Energy appears to claim that increasing reserve requirements in hours where solar does not operate has no cost impact because there are abundant reserves already available during these hours,

[34] DEC DEP SC Response to SACE CCL DR 1-25, Docket Nos. 2019-185-E and 2019-186-E, Exhibit D.

while simultaneously arguing, in other contexts, that solar has little or no capacity value because it does not operate during the time when the system has the greatest capacity need. But by uniformly adding reserve requirements 8760 hours per year, Duke Energy is increasing reserve capacity requirements during the very hours when they claim capacity is scarcest on the power system and solar is—according to Duke Energy—incapable of providing capacity.

Further, it is not only the capital cost of owning additional generation capacity that is of concern. As Mr. Wintermantel testified, increasing the online reserve also increases operating expenses:

> "In order to provide additional load following reserves, more generating units must be committed and synched to the grid. This, in turn, forces individual generators to operate further below their max output. When generators operate at levels below their maximum output, efficiency is reduced, which results in increased costs. Also, increasing load following reserves may require generators to start up more frequently, causing additional startup costs and maintenance costs."[35]

There are increased operating costs whenever spinning reserve requirements are increased. Therefore, adding reserve requirements 8760 hours per year, regardless of whether solar is actually operating or not, unrealistically inflates capital costs and operating responses.

[35] Wintermantel Direct Testimony at p. 8.

Q Can you provide an example showing why it is inappropriate and expensive to increase reserve requirements 8760 hours per year?

A Yes. Figure 6 provides an example hypothetical day for a utility with reasonably high solar penetration, perhaps comparable to Duke's Tranche 1 + 1,500 MW case.[36]

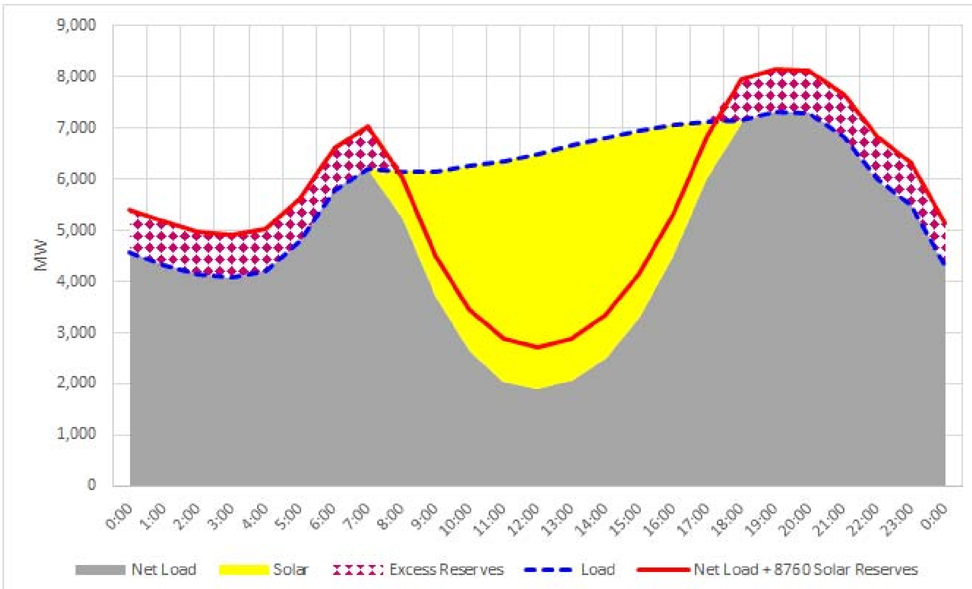

Figure 6: Solar integration reserves imposed around the clock are inappropriate and excessively expensive.

The dashed blue line in Figure 6 shows the system load. In this example the load peak is 7,322 MW at 7pm. The yellow area is 4,600 MW of solar generation. The gray area is the net load (total load less solar generation) which Duke's conventional generation must serve. It also has a 7,322 MW peak at 7pm, after sunset.

The *Ancillary Service Study* methodology imposes an 832 MW additional solar integration reserve requirement during all hours of this high solar example. The red line shows the on-line conventional generation capacity the *Ancillary Service Study* forces to

[36] A high solar penetration case is shown so that the individual pieces are clearer in the graph. The same impacts occur at all solar integration levels.

operate to serve the net-load and provide the required additional solar integration reserves.[37]

Note that on this example day the *Ancillary Service Study* methodology requires more conventional generation capacity (8,154 MW) to be installed, available, and operating in the solar case than it requires (7,322 MW) in the no solar case. The *Ancillary Service Study* methodology imposes this higher capacity requirement during hours when there is no solar generation operating and it is impossible for solar variability to create an imbalance on the power system.

The red checkered area shows the excess solar integration reserve requirement which is unjustified and serves no useful purpose. On this example day 58% of the solar integration reserve is excess. It imposes costs while providing no reliability benefit. It is not caused by increased solar generation because it is imposed when solar is not even operating. It only results from the arbitrary requirement to increase solar integration reserve requirements during all hours. The excess reserve burden is even greater on cloudy days when solar is not operating near full capacity.

This simple example shows that imposing increased solar integration reserve requirements during all hours results in increased total system capacity as well as increased operating costs during the majority of hours when solar is not even operating.

[37] There are also additional contingency reserves, regulation, and load following reserves required but these are the same in the with- and without-solar cases so are not shown in the example.

Q What would be the consequences if Duke actually operated with increased reserve requirements 8760 hours a year and only allowed spinning reserves to supply solar integration reserve requirements?

A If DEC and DEP actually operated with increased spinning reserves 8760 hours a year they would incur dramatically increased, unnecessary and inappropriate costs.

Q What would be the consequences if Duke operated reasonably but imposed the *Ancillary Service Study* calculated costs on solar generators?

A It seems unlikely that Duke will actually force its operators to carry additional solar integration reserves in the middle of the night. Similarly, it seems likely that Duke operators would prefer to use non-spinning reserves for $\text{LOLE}_{\text{FLEX}}$ "events," which the *Ancillary Service Study* stated "rarely occur" and "occur with much lower frequency,"[38] just as they currently do for the larger and faster conventional generation contingencies. In that case Duke would be inappropriately charging solar generators for costs that it does not actually incur.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q Please summarize your concerns with the *Ancillary Service Study* methodology and results?

A The analysis methodology and resulting solar integration charge is fatally flawed in two distinct ways. First, the *Ancillary Serve Study* overestimated the amount of required solar integration reserves because it used a $\text{LOLE}_{\text{FLEX}}$ reliability metric that is overly strict and unrelated to the physical balancing requirements of a utility operating within the Eastern Interconnection or the mandatory NERC and SERC reliability

[38] *Ancillary Service Study* at p.11.

requirements. The *Study* also overestimated the required solar integration reserves by linearly scaled solar variability instead of recognizing the natural aggregation benefits that occur at the solar fleet grows.

Second, the analysis methodology calculated excessively high costs to mitigate any increased solar integration reserves. The methodology applied increased reserve requirements during all hours, 8760 hours a year, even when solar is not operating and cannot increase power system variability and uncertainty. The methodology also forced all solar integration reserves to come from expensive online, spinning generation in spite of the fact that NERC and SERC allow (and Duke extensively uses) much lower cost off-line, fast-start, non-spinning reserves to be used as contingency reserves. Conventional generation contingencies are much larger and faster than solar imbalances (the instantaneous tripping of a 1000 MW generator, for example) and NERC mandatory reliability rules require Duke to rebalance its power system within 15 minutes of a major contingency while allowing up to 30 minutes to correct a solar imbalance, and then only if it is hurting interconnection frequency.

Q What is your conclusion regarding Duke Energy's proposed Solar Integration Charge given the issues you have identified with the *Ancillary Service Study*?

A The flaws in the *Ancillary Service Study* need to be fixed to determine if a solar integration charge is warranted. The Commission should reject the SISC as currently proposed.

Q Please summarize your recommendations for the Commission.

A Duke's proposed solar integration charge is flawed both in the way it estimated the amount of additional reserves and in its calculation of the cost of those reserves. The impacts for some of the flaws can be quantified while others simply require redoing the analysis with improved methods and metrics.

The analysis methodology should be modified, and the modeling tools upgraded. As explained in more detail in my report:

- Production cost modeling should reflect the actual NERC reliability and balancing requirements and operating practices. The $\text{LOLE}_{\text{FLEX}}$ metric should be replaced with one that is based on the physical operating characteristics of the DEC and DEP power systems and the Eastern Interconnection within which they operate as well as with the NERC and SERC reliability requirements.
- Results should be verified by comparing hourly modeling results of actual historic solar penetrations and weather conditions, ranging from no-solar to the current penetration, with actual historic reserve requirements and operations. Historic hourly reserve requirements should be documented by type including regulation, load following, and contingency reserves. Reserves should be distinguished as spinning or non-spinning. Hourly reserve requirements should be compared with historic operating conditions. Only then will it be possible to determine if the analysis method and metrics are valid for predicting future requirements.
- Reductions in short-term intra-hour variability for the aggregate solar generation fleet from the variability identified in the historic data should be reflected in the

analysis of each level of solar penetration studied. This alone would reduce the modeled variability for the Existing + Transition case by 24%.

- Solar variability should be continuously tracked and reported at least annually, along with penetration.
- Solar integration reserve requirements should not be imposed 8760 hours a year. Solar integration reserve requirements should be adjusted hourly and only imposed during times and under conditions when solar generation is expected to create increased reserve needs. Clearly solar integration reserve requirements should not be imposed when solar generation is not operating. In the example presented above, imposing solar integration reserve requirements during all hours resulted in 58% excess reserves.
- Any required solar integration reserves should be allowed to come from non-spinning resources. Assuming the ratio between Duke's spinning and non-spinning reserve costs is similar to that in PJM's Mid-Atlantic Dominion region this alone would result in an 85% decrease in reserve costs.
- A Technical Review Committee composed of outside variable renewable generation integration experts should be used to help design and guide the analysis.

The Commission should direct Duke to redo the solar integration cost analysis, correcting the errors listed. It should not impose a SISC until the results of the new study are available.

If the Commission decides that a SISC must be imposed pending the results of a valid study the charge should, at a minimum, be reduced 85% to reflect the lower cost of using non-spinning reserves, be reduced by a further 58% to reflect the majority of hours when solar is not generating and cannot possibly increase reserve needs, and be reduced by a further 24% to reflect the aggregation benefits already being experienced for the Existing + Transition case. Together these reductions would reduce the DEC solar integration charge from $1.10/MWH to $0.05/MWH for the Existing Plus Transition level of solar penetration while the charge for DEP would reduce from $2.39/MWH to $0.11/MWH. These proposed reductions do not correct for the inflated reserve requirements calculated based on the inappropriate $\text{LOLE}_{\text{FLEX}}$ reliability metric.

Q **Does this conclude your testimony?**

A Yes.

Kirby Exhibit A

Analysis of Duke Energy's Proposed Solar Integration Charge

Brendan Kirby, P.E – September 2019

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in a November 11, 2018 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" (*Ancillary Service Study*). Unfortunately, the study methodology, as implemented, is fundamentally flawed and the resulting solar integration charges are unsubstantiated, unjustified, and simply wrong.

The basic analysis methodology of comparing production cost simulations with and without solar, while adjusting reserves in order to maintain reliability, is well established and has been executed successfully by others. However, Duke's analysis is flawed because the *Ancillary Service Study*:

- Modeled DEC and DEP as isolated power systems, not their actual coordinated operation within the Eastern Interconnection by applying an inappropriate loss-of-load, one-in-ten-years, long-term system adequacy metric, not normally used for operations, rather than basing reserve requirements on the mandatory North American Electric Reliability Corporation (NERC) reliability standards to which Duke actually operates – over estimating the amount of required solar integration reserves;
- Improperly scaled solar plant intra-hour output variability data in a way that fails to accurately reflect geographic diversity benefits – again overestimating the amount of required solar integration reserves;
- Applied increased reserve requirements during all hours, 8760 hours a year, even when solar is not operating and cannot increase power system variability and uncertainty – greatly increasing the cost of any required solar integration reserves; and
- Forced all solar integration reserves to come from expensive online, spinning generation in spite of the fact that NERC and SERC allow (and Duke extensively uses) much lower cost off-line, fast-start, non-spinning reserves to be used as contingency reserves – again greatly increasing the cost of any required solar integration reserves.

As a result of these deficiencies, the solar integration costs developed in the *Ancillary Service Study* do not reflect actual increased reserve requirements or actual impacts on the operating costs that Duke will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements and operations. The solar data should be reanalyzed to reflect plant and system aggregation benefits. Additional solar integration reserve requirements should be adjusted hourly and only imposed during times and under conditions when solar generation is expected to create increased reserve needs. Simulated reserve shortfalls should be analyzed to determine the most cost-effective methods to adjust operations and/or add reserves to maintain reliability as solar generation increases, including allowing additional reserves to come from low cost non-spinning fast start generators and demand response.

Inappropriate Modeling of DEC and DEP as Isolated Power Systems

The *Ancillary Service Study* report states that "The utilities are modeled as islands for the Ancillary Service Study" (page 13). Note that treating DEC and DEP as islanded power systems in the *Ancillary Service Study* differs from how Duke actually plans and operates DEC and DEP as interconnected utilities. The stated reason for modeling DEC and DEP as islanded power systems in the *Ancillary Service Study* is that "it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements". This completely misunderstands the benefits of interconnected utility operations and the impacts on reliability reserves. Utilities started to interconnect over ninety years ago in order to increase reliability while reducing each utility's reserve requirements. This works because of the strong aggregation diversity benefits for load and generation variability under both normal and contingency conditions. Interconnected power systems are more resilient, reliable, and economic than islanded power systems. All utilities participating in an interconnection benefit from reduced reserve requirements. Additionally, DEC and DEP are members of the VACAR Reserve Sharing Group which explicitly shares contingency reserve obligations and reserves.[1] Further, Duke acknowledges that "the Companies modeled the avoided energy costs assuming that the DEC and DEP systems were dispatched jointly" (SACE Data Request No. 1 Item No. 1-11). The NERC reliability standards are also based on interconnected operations. Determining reserve requirements for islanded versions of DEC and DEP is irrelevant to the way the power systems, including DEC and DEP, are actually designed, built, and operated.

Inappropriate Reliability Metrics and Requirements

The *Ancillary Service Study* attempts to compare total production costs with and without solar generation in order to determine the cost of integrating additional solar generation (after compensating for the change in solar versus conventional energy value itself). In order to make a fair comparison, it is necessary to hold reliability constant in the no-solar and solar generation cases so that calculated integration costs are not reduced (or increased) as the result of a drop (or increase) in reliability. Reliability is held constant by adding reserves to the solar cases until reliability matches the non-solar base case. This basic methodology of using security constrained unit commitment and economic dispatch modeling is well established and has been used in numerous renewables integration studies including the National Renewable Energy Laboratory (NREL) Eastern Wind Integration and Transmission

[1] *See* VACAR South Reliability Plan, https://www.nerc.com/comm/OC/ORS%20Reliability%20Plans%20DL/VACAR_South_Reliability_Plan_20180928.pdf

Study and the Western Wind and Solar Integration Studies.[2] The methodology has also been used by utilities to develop renewables integration charges.[3,4]

The assessment methodology reported on in the *Ancillary Services Study* correctly recognizes that it is the continuous balancing of generation and load that requires reserves and drives system reliability. Rather than basing the DEC and DEP balancing requirements on mandatory NERC standards, however, the study introduces a completely arbitrary pair of misnamed loss-of-load-expectation (LOLE) metrics which attempt to identify instances of insufficient generation capacity or flexibility. These metrics are misnamed because there would be no loss of load expected during the identified imbalances for DEC or DEP as they actually operate in the Eastern Interconnection. In interconnected operations, small imbalances in one BA manifest themselves as deviations from scheduled interchange flows, not loss of load; load shedding is not required. It is only the aggregation of imbalances from all the BAs in the interconnection that influence frequency and potentially impact reliability. Under normal operating conditions, imbalances in one BA tend to counteract imbalances in another BA such that the total interconnection imbalance is much less than the sum of the absolute values of the individual BA imbalances. Interconnection greatly increases reliability while dramatically reducing individual BA balancing requirements. Consequently, NERC reliability standards do not require the level of reserves or balancing operations necessary to meet the 0.1 LOLE for 5-minute balancing that is the basis of the *Ancillary Service Study* and the proposed solar integration charges. These issues are explained in further detail below.

DEC and DEP Ancillary Service Study *Balancing Metrics and Requirements*

The *Ancillary Service Study* established two LOLE metrics: $LOLE_{CAP}$ and $LOLE_{FLEX}$. As described below, the two LOLE metrics used in the study are not appropriate standards and result in inaccurate and improper conclusions.

The production cost modeling looked at each power system (DEC and DEP) as though they were physically isolated islands and simulated the generation/load balance every five minutes. $LOLE_{CAP}$ looked

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[2] EnerNex, *Eastern Wind Integration and Transmission* Study, National Renewable Energy Laboratory, NREL/SR-5500-47078, February 2011 – GE Energy, *Western Wind and Solar Integration Study*, National Renewable Energy Laboratory, May 2010 – D. Lew et al, *The Western Wind and Solar Integration Study Phase 2*, National Renewable Energy Laboratory, NREL/TP-5500-55588, September 2013

[3] *See e.g.* Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF

[4] Commission and utility interest in variable renewables integration charges appears to be declining, making it difficult to find examples of well designed integration charges. Analysts are recognizing that all generators have characteristics that impose costs on the power system. "Base load" generators, for example, are typically inflexible with high minimum loads, long startup times, and slow ramp rates. These limitations impose costs when lower-cost generation is available at low net-load times but cannot be used because the base load generators must run. These costs are not imposed on base load generators as an integration charge, however. Similarly, contingency reserve costs are not charged back to large conventional generators even though it is the size of the large generators that disproportionately cause higher contingency reserve costs. Commissions are reluctant to impose integration charges on base load generators and instead allow security constrained unit commitment and economic dispatch optimization, as well as electricity markets, to optimize the utilization of the generation fleet.

for instances when there was insufficient generation capacity to cover total load. $LOLE_{FLEX}$ looked for instances when there was insufficient generation ramping capability to follow the net system load. The study imposed a 0.1 LOLE requirement which only allowed one 5-minute imbalance event every ten years.

> "Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is 'one day in 10 years' LOLE, or 0.1 LOLE." "To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period." (page 10).

While it is true that a LOLE of 0.1 is an appropriate and accepted standard for long-term planning of generation capacity, it is completely inappropriate, unnecessary, not required by NERC standards, and excessively expensive when applied to actual operations. The *Ancillary Service Study* acknowledges that "[r]eliability targets for operational reliability are covered by NERC Balancing Standards" and are not dictated by an arbitrary LOLE of one event in ten years. The Study further states that "[t]he Control Performance Standards (CPS) dictate the responsibilities for balancing areas (BA) to maintain frequency targets by matching generation and load" (page 10). Most importantly, with interconnected operations a small imbalance in one BA will not result in a LOLE event, which is why NERC does not require continuous perfect balancing from each BA.

The *Ancillary Service Study* acknowledges that actual NERC reliability and balancing requirements were not modeled, and the 0.1 LOLE was substituted, presumably because the modeling capability was insufficient to represent actual balancing capabilities and requirements:

> "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2 standards is a critical component of a solar ancillary service cost impact study. However, ***simulating violations of these standards is challenging***. While the ***simulations performed in SERVM do not measure CPS violations directly***, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. ***Any periods in which generation is not able to meet load and minimum ancillary service requirements are recorded as reliability violations***." … "So, while there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, ***there is not a standard for loss of load due to flexibility shortfalls as measured by SERVM***. Absent a standard, this study assumes that maintaining a constant operational reliability as solar penetration increases is an appropriate objective. ***Simulations of the DEC and DEP systems with current loads and resources were calibrated to produce*** $LOLE_{FLEX}$ ***of 0.1 events per year***." (emphasis added, page 10).

The 0.1 $LOLE_{FLEX}$ requirement is unrelated to NERC reliability standards and is not a reasonable analysis proxy for the actual balancing or reliability requirements. As the *Ancillary Service Study* acknowledges, SERVM cannot accurately measure NERC reliability violations. The Study invented a $LOLE_{FLEX}$ standard that is an unreasonable proxy for actual balancing and reliability requirements.

NERC Mandatory Reliability Balancing Requirements

As the *Ancillary Service Study* acknowledges, actual power system reliability and reserve requirements are established by NERC. These requirements are laid out in mandatory NERC reliability standards which are approved by the Federal Energy Regulatory Commission (FERC) and the Canadian provincial governments. Two NERC standards are particularly relevant[5]:

- BAL-001-2 – Real Power Balancing Control Performance
- BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

These standards establish reliability and reserve requirements for Balancing Authorities (BAs) such as DEC and DEP. Importantly, and fundamentally, the reliability requirements are based on operations within an interconnection; specifically, within the 720,000 MW Eastern Interconnection in Duke's case.[6] This is fundamentally important because with interconnected utility operations, small imbalances within one BA do not result in Loss of Load events under normal conditions. In fact, imbalances are occurring all the time under normal conditions. The NERC standards limit the magnitude and frequency of allowed imbalances, but they do not attempt to eliminate them or restrict them to one-event-in-ten-years.

Obsolete CPS2 Requirement

The *Ancillary Service Study*[7] references two NERC reliability metrics: CPS1 and CPS2. CPS2 is no longer applicable, however. It was replaced in July 2016 with the BAAL requirement, discussed below, when BAL-001-02 became the effective standard. CPS2, however, was a much laxer balancing requirement than the *Ancillary Service Study* 0.1 $LOLE_{FLEX}$ requirement. CPS2 measured balancing over 10-minute intervals and required compliance only 90% of the time.

CPS2[8]: $\text{Monthly-AVG}_{10\text{-minute}}(ACE)<L_{10}$ Where L_{10} = 92 MW for DEC and 17 MW for DEP[9]

So, rather than allowing only one 5-minute event every ten years, CPS2 allowed ACE to remain high or low for 5,256 10-minute intervals per year and bounded average ACE to 92 MW for DEC and 17 MW for DEP for the remaining 90% of the time.

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[5] Additional standards, such as BAL-003-1 — Frequency Response and Frequency Bias Setting, amplify and support the balancing requirements.

[6] NERC 2018 Summer Reliability Assessment.

[7] "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and **CPS2** standards is a critical component of a solar ancillary service cost impact study." (emphasis added, page 10).

[8] "BAL-001-1 — Real Power Balancing Control Performance", NERC.

[9] "BAL-003-1 Frequency Bias Setting and L10 Values for 2017", NERC, March 28, 2017.

Applicable NERC Balancing Requirements

BAL-001-2 – Real Power Balancing Control Performance establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). NERC balancing requirements under contingency conditions are discussed further below.

CPS1 Reliability and Balancing Requirement

CPS1 limits the <u>*annual average*</u> 1-minute area control error deviations. ACE deviations result from difference between a BA's total instantaneous generation (plus scheduled imports) and total instantaneous load (plus scheduled exports) (plus the BA's instantaneous frequency support obligation).[10] While 100% compliance is required, this metric may be a bit deceptive. The CPS1 metric runs between 0% and 200%, meaning continuous perfect balancing would result in a CPS1 score of 200%, not 100%. Therefore, 100% compliance does not mean compliance during every minute. The CPS1 requirement is reflected in the following formula:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \epsilon_1^2$$ [11]

This formula is simpler than it at first appears. It says that the annual average of the instantaneous ACE values, times the instantaneous ΔF [frequency deviation from the scheduled frequency (usually 60 Hz)], must be less than 0.000324.[12] It is the multiplication of ACE times ΔF that makes balancing operations easier (and analysis harder). During times when frequency is exactly equal to 60 Hz then there is no CPS1 limit on ACE. When frequency is exactly equal to 60 Hz then ΔF is zero, which is multiplied by ACE and the result remains zero no matter how large ACE is. Physically this means that the BA can be far out of balance with no penalty when frequency is exactly 60 Hz. This makes sense for reliability because, if frequency is exactly equal to 60 Hz (ΔF is zero) the overall interconnection is not experiencing an overall imbalance and an individual BA's imbalance is not a reliability threat.

Further, not all imbalances are bad. If frequency is below 60 Hz (ΔF is negative) and the BA is over-generating (excess solar, for example) then the BA's imbalance is supporting reliability by reducing the interconnection's overall imbalance and helping to push frequency back up to 60 Hz. CPS1 calculation credits the BA for that help. The excess generation is a reliability benefit and there is no requirement to reduce ACE. Conversely, if frequency is above 60 Hz (ΔF is positive) and the BA is under-generating (excess load or solar is suddenly reduced, for example) the BA is again helping overall power system

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[10] Because BA load cannot be measured directly it is determined indirectly by measuring the BA's generation and interconnection flows (imports and exports). NERC defines ACE as "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias" (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018).

[11] NERC Standard BAL-001-1 — Real Power Balancing Control Performance.

[12] ϵ_1 for the Eastern Interconnection is 0.018 Hz (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018) ϵ_1^2 is 0.000324.

reliability by reducing the interconnection's overall imbalance and helping to push frequency back down to 60 Hz, and CPS1 again credits the BA.

Frequency in the Eastern Interconnection varies constantly over a small range. It is above 60 Hz (ΔF is positive) about half the time and below 60 Hz (ΔF is negative) about half the time as shown in Figure 1.1 from the November 2018 NERC report *2018 Frequency Response Annual Analysis*:

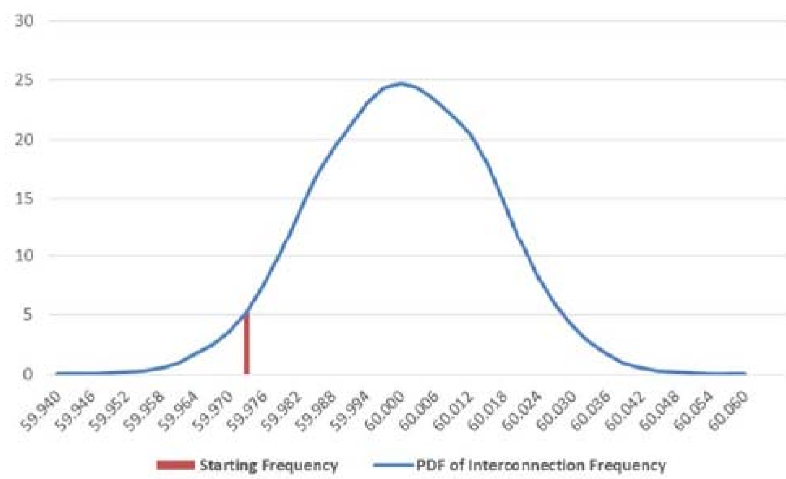

Figure 1.1: Eastern Interconnection 2014–2017 Probability Density Function of Frequency

Given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the 720,000 MW Eastern Interconnection, CPS1 does not require correction of imbalances about half of the time. This significantly reduces the balancing reserves that Duke must have available and reduces the times Duke must exercise those reserves.

BAAL Reliability and Balancing Requirement

Like CPS1, the Balancing Authority ACE Limit (BAAL) does not require perfect compliance. In fact, BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. BAAL limits are specific to each BA and depend on the actual interconnection system frequency at each time interval. As shown in Figure 2 below, ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Again, given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the very large Eastern Interconnection, BAAL does not require correction of imbalances about half of the time.

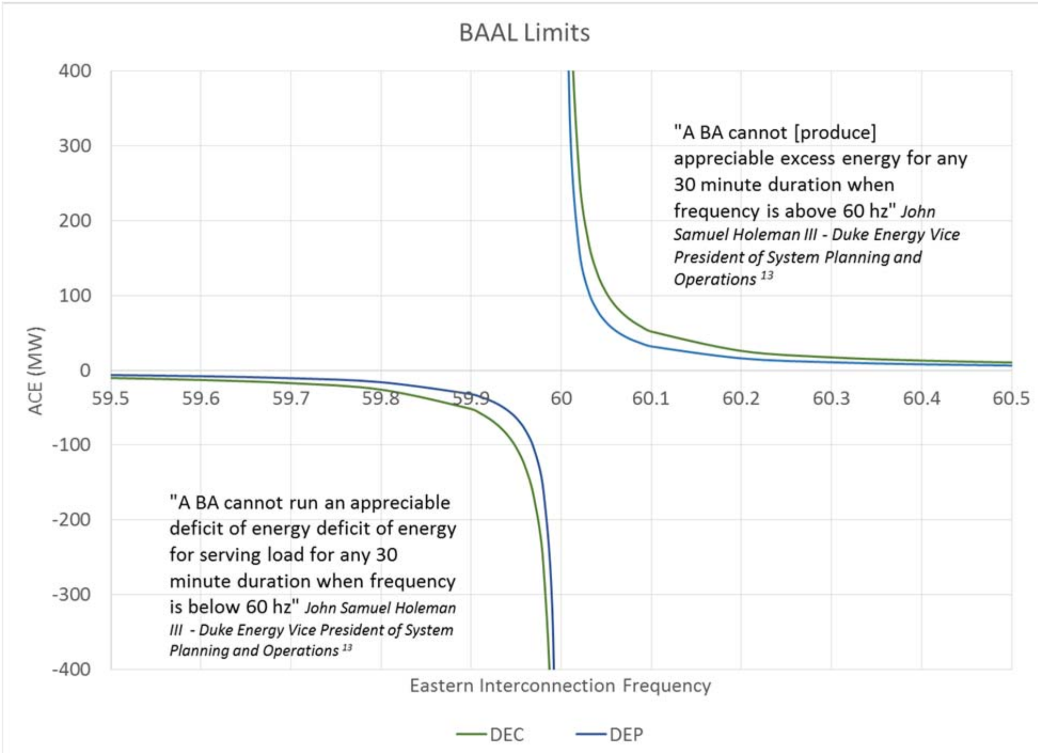

Figure 2 BAAL does not require perfect balancing

BAL-002 – Disturbance Control Standard (DCS)

NERC reliability standards recognize that large conventional generators occasionally fail unexpectedly and that the normal generation and load balance cannot be maintained by the host BA during such an event. The "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event" standard provides the requirements to restore the generation and load balance after a reportable contingency.[14] BAL-002 contains three balancing related requirements. The first requirement is to restore the generation and load balance within the Contingency Recovery Period (15 minutes) by using the Contingency Reserves. The second requirement is to plan to have Contingency Reserves equal to or greater than the most severe single contingency available at all times. The third requirement is to restore the Contingency Reserves within 105 minutes of the start of the contingency.

There are two DCS issues that are important for the *Ancillary Service Study* analysis. The first is that NERC requires a BA to rebalance its power system within 15 minutes of a disturbance, not within 5 minutes as required by $LOLE_{FLEX}$. The second is that NERC does not require a BA to hold or use only spinning reserves to respond to contingencies. Non-spinning reserves from much lower cost off-line fast-start generators and demand response are allowed. Specific requirements for how much of the

[13] Direct Testimony of John Samuel Holeman III, Duke Energy Vice President of System Planning and Operations, Testimony in Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2016 Docket No. E-100, Sub 148.

[14] "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event", NERC.

contingency reserve must be spinning are set by the Regional Reliability Councils. SERC is the Regional Reliability Council for DEC and DEP. SERC allows all contingency reserves to be non-spinning.

The importance of NERC and SERC contingency response and reserve requirements is not because of the impact increased solar generation will have on DEC and DEP contingency response requirements. Solar generation plants are typically small compared with large fossil and nuclear generators and consequently do not add to contingency reserve requirements. The important points are, first, that even for very large and fast imbalances (the instantaneous tripping of a 1,000 MW generator, for example) NERC allows 15 minutes for the BA to balance its power system, not 5 minutes. Second, SERC allows low cost non-spinning reserves to be planned for and used as the reliable response to imbalances that are much larger and faster than any imbalances that could be caused by increased solar generation.

Use of Curtailed Solar Generation for Contingency Reserves

Curtailed solar (and wind) generators can be ideal *suppliers* of contingency (and other) reserves. Modern solar plants can control their output faster and more accurately than conventional generators. If they are equipped with automatic generation control (AGC) they can provide that response to the system operator during contingencies. Solar plants normally operate at their full available output, and have no reserve capacity to offer, because they have zero marginal production cost and are therefore more economic than fuel burning generators. If, however, a solar generator is curtailed for some reason it will have available generation capacity that could be called upon to support power system reliability. Any solar generator that is *supplying* reserves should be compensated for provision of that service.

Interconnection Frequency Does Complicate Modeling – How to Solve That

The *Ancillary Service Study* is correct when it states that "[u]nderstanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2[15] standards is a critical component of a solar ancillary service cost impact study. However, **simulating violations of these standards is challenging**." (page 10, emphasis added). The Study is only partly correct when it states that "[w]hile the simulations performed in SERVM do not measure CPS violations directly, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation." (pages 10-11). It is correct to state that the modeling does not measure CPS violations. It is not correct to imply that the analysis effort and the LOLE reliability metric are in any way suitable substitutes for the NERC CPS1, BAAL, or DCS reliability requirements.

The difficulty in directly modeling NERC balancing requirements is because CPS1 and BAAL both require balancing *only* when ACE drives the interconnected power system frequency further away from 60 Hz: each metric uses (ACE x ΔF) in assessing instantaneous balancing performance.[16] The NERC reliability metrics *credit* generation/load imbalances when they are helping to restore the overall interconnection

[15] Again, the correct NERC reliability requirements are CPS1, BAAL, and DCS, but the concept that it is mandatory NERC reliability standards that govern balancing requirements is correct.

[16] Excess generation is bad only when frequency is above 60 Hz and excess load id is bad only when frequency is below 60 Hz.

system frequency to 60 Hz. This makes actual balancing for the individual utility easier, not harder, than when operating as an isolated system.

Perfect modeling of NERC reliability standards is not necessary, but the proxy modeling balancing requirement must approximate the physical balancing requirements imposed by NERC standards. A recent Idaho Power study[17] of variable renewable generation integration (solar and wind) studied solar penetration levels of 47% of peak load and wind-plus-solar penetrations of 67% of peak load. For reference, the Duke *Ancillary Service Study* only studied solar penetrations ranging from 5% to 33% of peak load.[18] The Idaho Power study also employed production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels. Idaho Power targeted reserves (in both the base and renewables cases) sufficient to compensate for 99% of the 5-minute balancing deviations. That is, Idaho Power allowed a cumulative 90 hours per year of deviations rather than one-event-in-10-years:

> "The target to capture 99 percent of deviations for this study is considered appropriate in ensuring generators have sufficient reserve requirements for all but approximately 90 hours per year. Importantly, the targeted 99 percent is the criterion held for both simulations performed for this study: the base case simulation of load combined with wind, and the test case simulation of load combined with wind and solar. This ensures both simulations are designed to bring about an equivalent level of system reliability, rendering the selected reliability level relatively immaterial from the perspective of comparing production cost differences between paired simulations." (page 8).

Duke's requirement to balance generation and load every 5 minutes does not reasonably approximate NERC's actual requirement to balance within 30 minutes (and then only if the imbalance is hurting interconnection frequency). Idaho Power's requirement to balance 99% of the 5-minute deviations, while still very conservative, is a better proxy for the actual NERC standards.

Reserve Requirements Increased 8760 Hours Per Year Rather Than When Required

The *Ancillary Service Study* methodology is based on comparing power system reliability after solar is added with pre-solar, base case power system reliability:

> "When solar is added, ancillary services in the form of load following reserves are increased until the system reliability is returned to the same level that existed before the solar was added."[19]

The *Ancillary Service Study* modeled solar integration reserve requirements are increased 8760 hours per year, however, not only during times when increased solar is expected to result in reserve shortfalls.[20] Consequently, the model calculates the increased cost of holding increased reserves even

[17] Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF.
[18] Existing, transition, Tranche 1, and plus 1500 MW of solar generation for DEP and DEC.
[19] Wintermantel, August 2019 Direct Testimony, pg 14
[20] SACE Data Request 1-25.

during hours when there is no solar generation; the middle of the night, for example. This could be an appropriate modeling method if increased reserves had to come from new generating capacity – a new generator cannot be purchased for only a few hours a year – but that is not the case for increased operating reserves. Increased operating reserves often do not come from installing new generation. Increased operating reserves, and increased operating reserve costs, come from changing the operating pattern of existing generators to hold additional capacity online and unloaded. Operating reserve requirements can and should be adjusted to the operating conditions that require them. If, for example, modeling determines that reserve shortfalls only occur when specific conventional generators are out for maintenance then increased reserves should be modeled for those hours. Reserve requirements should not be increased during winter nights or late summer evenings when solar is not operating. The high calculated solar integration cost could easily result from the high cost of holding additional reserves during times when solar is not imposing an additional variability or uncertainty burden.

This is especially important for solar generation modeling because solar tends to create its own reserves. As solar generation increases it displaces conventional generation. The displaced conventional generation capacity is available as a reserve in case the solar generation is not available. Increasing the reserve requirements during hours when solar is not producing imposes a cost for a reserve that will never be used.

Figure 3 provides an example hypothetical day for a utility with reasonably high solar penetration, perhaps comparable to Duke's Tranche 1 + 1,500 MW case.[21]

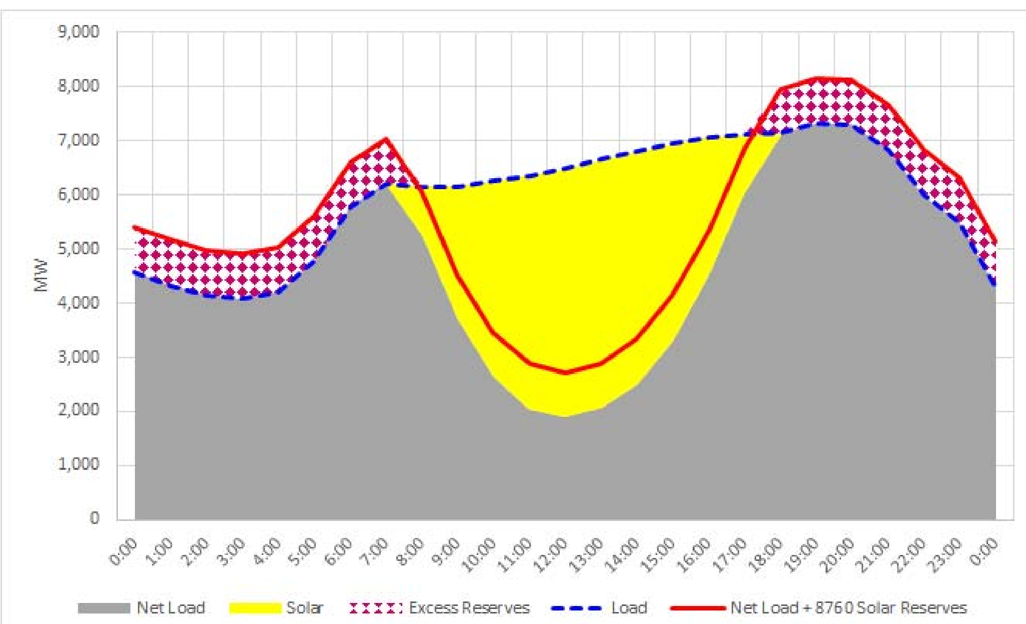

Figure 3 Solar integration reserves imposed around the clock are inappropriate and excessively expensive

[21] A high solar penetration case is shown so that the individual pieces are clearer in the graph. The same impacts occur at all solar integration levels.

The dashed blue line in Figure 3 shows the system load. In this example the load peak is 7,322 MW at 7pm. The yellow area is 4,600 MW of solar generation. The gray area is the net load (total load less solar generation) which Duke's conventional generation must serve. It also has a 7,322 MW peak at 7pm, after sunset.

The *Ancillary Service Study* methodology imposes an 832 MW additional solar integration reserve requirement during all hours of this high solar example. The red line shows the on-line conventional generation capacity the *Ancillary Service Study* forces to operate to serve the net-load and provide the required additional solar integration reserves.[22]

Note that on this example day the *Ancillary Service Study* methodology requires more conventional generation capacity (8,154 MW) to be installed, available, and operating in the solar case than it requires (7,322 MW) in the no solar case. The *Ancillary Service Study* methodology imposes this higher capacity requirement during hours when there is no solar generation operating and it is impossible for solar variability to create an imbalance on the power system.

The red checkered area shows the excess solar integration reserve requirement which is unjustified and serves no useful purpose. On this example day 58% of the solar integration reserve is excess. It imposes costs while providing no reliability benefit. It is not caused by increased solar generation because it is imposed when solar is not even operating. It only results from the arbitrary requirement to increase solar integration reserve requirements during all hours. The excess reserve burden is even greater on cloudy days when solar is not operating near full capacity.

Imposing higher reserve requirements during hours when they are not required likely greatly increases the calculated solar integration cost. The 1-day-in-10-years $LOLE_{FLEX}$ reliability metric compounds the concern. Ten years of reserve costs, 87,600 hours, are imposed for one 5-minute reserve shortfall.

Imposing increased reserve requirements only during hours and under conditions where increased solar generation may result in reserve shortfalls will greatly reduce the calculated solar integration charge.

Inappropriate Failure to Consider Non-Spinning Reserves

The *Ancillary Service Study* methodology requires the additional solar integration operating reserves to be spinning reserves: additional online, unloaded generation capacity.[23] That requirement is inappropriate, especially since the $LOLE_{FLEX}$ metric used by the study imposes a 1-event-in-10-year reliability limit. Rare imbalances still impose an increased reserve requirement but NERC and SERC allow utilities to use much lower cost non-spinning contingency reserves for imbalances that are must faster and larger than solar imbalances. Balance must be restored within 15 minutes for a contingency event

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[22] There are also additional contingency reserves, regulation, and load following reserves required but these are the same in the with- and without-solar cases so are not shown in the example.

[23] "Spinning reserves and load following up reserves are identical and represent the sum of the 60-minute ramping capability of each unit on the system. To maintain operational reliability as solar resources are added, the load following up reserves are increased and compared to the Base Case level of load following required to meet LOLEFLEX of 0.1 events per year in the scenario without any solar." *Ancillary Service Study*, page 42

while NERC allows 30 minutes for restoring a solar imbalance. Spinning reserves should only be utilized for frequent imbalances, ones expected once or more per day, not for $LOLE_{FLEX}$ events which the *Ancillary Service Study* says "rarely occur".[24]

This is important because non-spinning reserves are much lower cost than spinning reserves. While spinning and non-spinning costs for DEP and DEC are not publicly available, hourly ancillary service prices are publicly reported for all of the organized markets. In the Electric Reliability Council of Texas (ERCOT) region, for example, non-spinning reserve costs were only 44% of spinning reserve costs for all of 2018.[25] In the California Independent System Operator (CAISO) region non-spinning reserve costs were only 26% of spinning reserve costs for all of 2018.[26] The PJM RTO reports hourly ancillary service prices for the entire RTO and for the Mid-Atlantic Dominion region. Non-spinning reserve costs were only 7% of spinning reserve costs for the entire RTO and 15% of the spinning reserve costs for the Mid-Atlantic Dominion region for all of 2018.[27]

Allowing the model to use non-spinning reserves will greatly reduce the calculated solar integration charge. The Mid-Atlantic Dominion region is the closest geographically to the DEP and DEC service territories and may provide the best estimate of reserve costs for Duke. Assuming a similar relationship between the costs for non-spinning and spinning reserves the DEC solar integration cost would be reduce from $1.10/MWH to $0.17/MWH for the Existing Plus Transition level of solar penetration while the cost for DEP would reduce from $2/39/MWH to $0.36/MWH, even assuming no corrections to the amount of reserves required.

Inappropriate or Questionably Synthesized Solar Data

Of necessity, the *Ancillary Service Study* (and any planning study) modeled solar sites that do not yet exist and for which there is no actual data. Consequently, appropriate solar plant output data must be synthesized for the analysis. It is important that the synthesized data captures aspects of the actual solar plants that will be built. It is also important that the synthesized data represents data that is synchronized to the load data it is paired with to accurately represent net power system variability and uncertainty.

The Study states "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load." (page 26). This is a reasonable start. The study also notes:

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[24] *Ancillary Service Study*, page 11.

[25] Only one month was analyzed as being typical. Historical DAM Clearing Prices for Capacity, (last accessed Sept. 10, 2019).
http://mis.ercot.com/misapp/GetReports.do?reportTypeId=13091&reportTitle=Historical%20DAM%20Clearing%20Prices%20for%20Capacity&showHTMLView=&mimicKey.

[26] California ISA, Market Performance Reports January 2018-October 2018, http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx (go to "Market Performance Reports", then "Monthly market performance reports" then "Monthly market performance reports 2018" to access a list of monthly reports that can be downloaded individually).

[27] PJM, Data Miner 2: Public Data, (last accessed Sept. 10, 2019) http://dataminer2.pjm.com/list.

"Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, *the fact that larger units are coming on may dampen the diversity benefit*. For this study, *the raw historical data volatility was utilized along with a distribution that has 75% of the raw data volatility to serve as bookends in the study for the "+1,500" MW solar scenarios*." (pages 30-31, emphasis added).

This is completely unreasonable. Linearly scaling (doubling variability when the solar resource capacity doubles) is not realistic. The relative intra-hour variability of an aggregation of solar plants (or loads or wind generators) *declines* as the aggregation grows. This is because the short-term variations at one solar plant are not coupled to the short-term variations at other solar plants. The geographic separation of the solar plants prevents cloud shadow edges from crossing multiple solar generators simultaneously.[28]

An examination of the historic solar output data for DEP and DEC shows this decline in relative variability.[29] For example, for the month of July 2018 DEP had a maximum solar output of 1,630 MW while DEC had a maximum solar output of 427 MW.[30] The maximum coincident solar output for the combination of DEP and DEC was 2,041 MW, just 0.8% below the sum of the DEP plus DEC maximum solar outputs. As expected, maximum solar output is closely correlated for DEP and DEC. Aggregating DEP and DEC does not greatly reduce the maximum solar output of the aggregation. By contrast, the relative short-term intra-hour variability of the aggregation of DEP and DEC is significantly lower than the sum of the variability of the two BAs. The hourly average standard deviation of the DEP intra-hour variability for July 2018 was 9.7 MW.[31] The hourly average standard deviation of the DEC intra-hour variability for July 2018 was 3.6 MW.

If short-term variability scaled linearly as the *Ancillary Service Study* claims, then the hourly average standard deviation of the short-term variability for the net Duke system would be expected to be 13.3 MW. Instead, the hourly average short-term variability had a standard deviation of only 10.3 MW, just 78% of what linear scaling predicts. The 10.3 MW is also exactly what would be expected for completely uncorrelated short-term variability aggregation for DEP and DEC.

Examining all the historic data Duke provided also shows the strong aggregation benefits of reduced relative variability as the solar aggregation grows. Figure 4 shows that solar generation increased significantly in both DEP and DEC between April 2016 and July 2018. Figure 5 shows that short-term intra-hour variability increased as well. Figure 6, however, shows that short-term variability *declines*

[28] A. Mills and R. Wiser, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Ernest Orlando Lawrence Berkeley National Laboratory, September 2010.

[29] SACE Data Request No. 2 Item No. 2-30 asked for, and Duke provided, 5-minute aggregate solar and load data for DEP and DEC for April 2016 through August 2018.

[30] Maximum solar output is used as a proxy for solar capacity because Duke did not provide data about which solar plants are included in the aggregate solar output data.

[31] The appendix discusses why the use of standard deviation for quantifying short-term variability is both appropriate and more useful for comparisons than a probability distribution.

relative to the maximum solar generation, both as solar penetration increases through time and when comparing the net Duke system with DEP and DEC individually. That is, the existing DEC and DEP solar data shows that variability does not scale linearly with solar generation fleet size but instead exhibits strong aggregation benefits.

With the historic data showing the expected trend of short-term variability declining as solar penetration increases, the assumption of linear scaling is clearly unjustified.

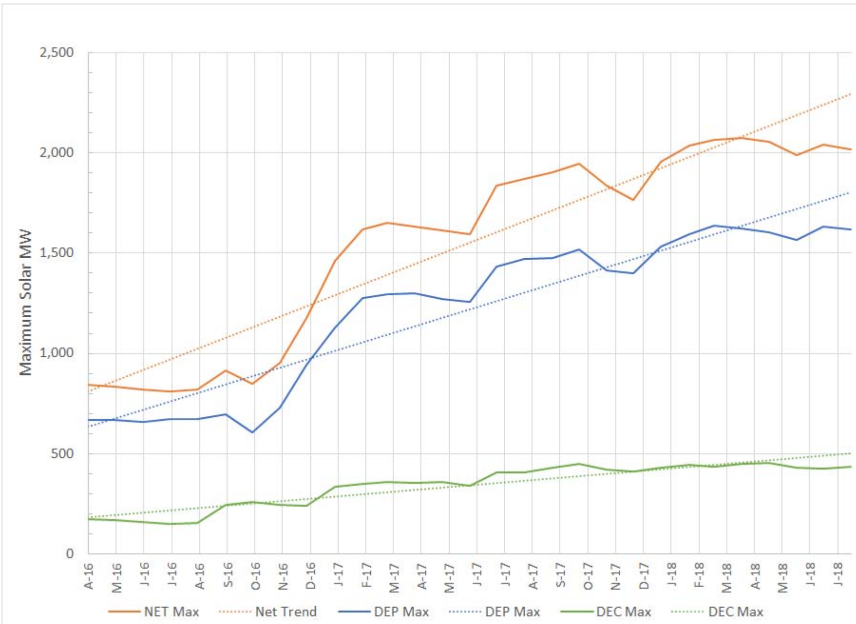


Figure 4 Solar generation increased significantly in DEP and DEC between April 2016 and July 2018

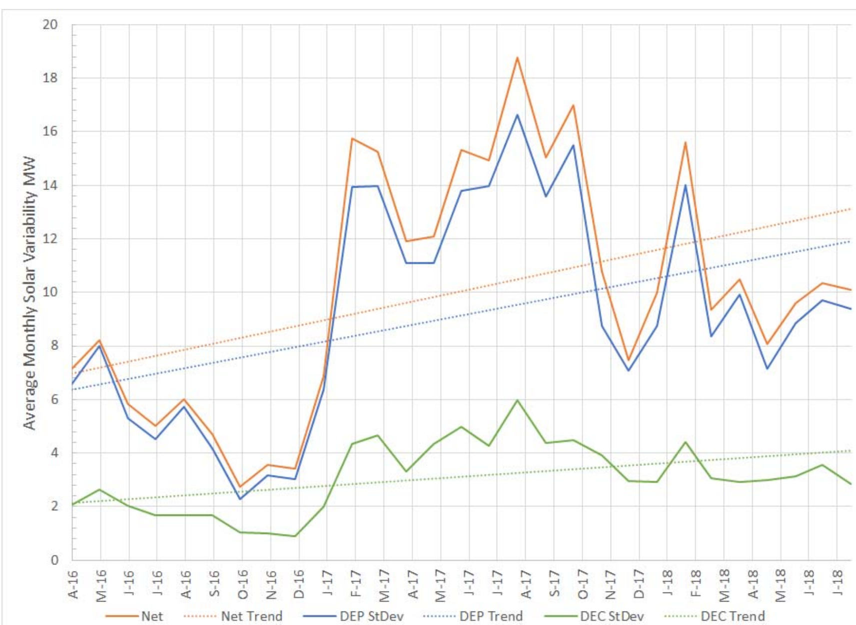


Figure 5 Short-term variability also increased in DEP and DEC between April 2016 and July 2018

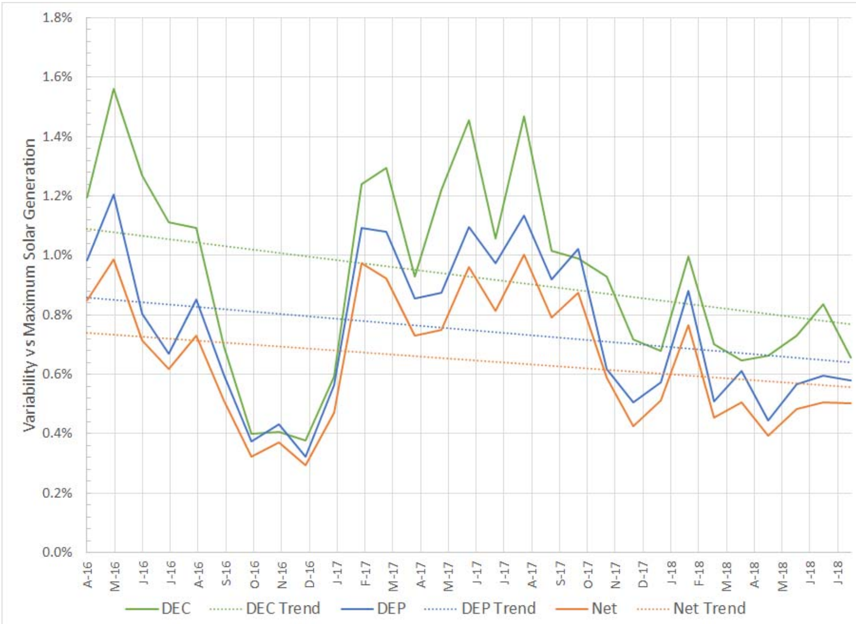


Figure 6 Variability relative to maximum solar declines as solar penetration increases.

Concerns with the *Ancillary Service Study* analysis get worse. The study says that it spread the simulated solar plants over 13 locations throughout the DEC and DEP service territories. Thirteen locations is not a lot of diversity for 7,630 MW of solar generation in the Existing + Tranche 1 + 1500 MW case.

Much less solar diversity was actually assumed in the modeling. Tables 5 and 6 show that 22% of the DEP solar plants and 24% of the DEC solar plants are at single sites (791 MW at site C4 for DEP and 800 MW at site B3 for DEC). Further, 78% of the DEP solar and 85% of the DEC solar was modeled at just four sites each. Even if the solar plants were evenly distributed across all locations that would result in thirteen 586 MW solar plants that cover 3,000 acres (4.6 square miles) each. What might appear to be a reasonable attempt at site diversity is, in fact, singularly lacking in diversity. The use of four mega-projects to represent solar variability totally misrepresents the policy issue at stake and actual character of the Duke systems.

Even if an 800 MW solar plant covering 4,000 acres were built, it would have a significant reduction in short-term variability compared with existing solar plants simply from its own geographic size.

Analysis of the historic solar generation shows that it is much more reasonable to assume that the short-term (5-minute) variability and uncertainty of new solar generation plants will be uncorrelated with the short-term variability and uncertainty of the existing solar generation plants, and with each other. Further, the *Ancillary Service Study* report states: "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load" (page 26) and "the five-minute data used to develop intra-hour load volatility was developed from actual data ranging from October 2016 - September 2017" (page 27). Assuming that "the 1 year of historical five-minute data for solar resources" was also October 2016 through September 2017, then the DEC maximum solar increased from 244 MW to 431 MW during the historic calibration year while the DEP solar fleet increased from 697 MW to 1,476 MW. Total Duke solar generation thus increased from 941 MW to 1,907 MW, averaging 1,424 MW during the historic year that was apparently used to calibrate solar variability. This is significantly smaller than the 679 MW of "Existing" solar generation for DEC and 1,923 MW for DEP (2,602 MW total) listed in Table 3 of the *Ancillary Service Study* report.

The *Ancillary Service Study* analyzed total solar penetrations ranging from 2,602 MW for the "Existing" fleet to 7,630 MW for the "Existing+Transition+Tranche 1+1500". That is a range of 1.8 to 5.4 times the size of the solar fleet that was actually analyzed for short-term variability impacts. This results in short-term variability and uncertainty expectations of:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

This large increase in solar penetration creates significant diversity benefits. At a minimum, Duke's analysis should be modified to reflect the reduced variability that increased solar penetration will exhibit.

Next Steps – What Should Be Done?

The analysis methodology should be modified, and the modeling tools upgraded if necessary:

- Production cost modeling should be based on actual NERC reliability and balancing requirements and operating practices.
- Reductions in short-term intra-hour variability for the aggregate solar generation fleet from the variability identified in the historic data should be reflected in the analysis of each level of solar penetration studied.
- Solar integration reserve requirements should not be imposed 8760 hours per year, even during times when solar is not operating. Increased reserve requirements should only be imposed during hours and under conditions when solar variability and uncertainty is likely to increase system balancing requirements.
- Non-spinning resources should be allowed to supply additional reserve requirements.

Once these steps are taken, it will be possible to begin to determine if any solar integration charge is warranted.

Duke should also consider utilizing a Technical Review Committee (TRC), composed of outside experts on variable renewables integration. TRCs have been successfully used by many utilities to help guide their integration studies and to utilize the latest and best integration study practices.[32] The Energy Systems Integration Group has published guidelines for TRC involvement in renewables integration studies.[33]

Improvements to Production Cost Modeling Methodology

Each BA should be modeled as part of the interconnected power system, not as an isolated island. Balancing and reliability requirements based on the mandatory NERC reliability standard BAL-001-02 and metrics based on CPS1 and BAAL should be used, reflecting NERC's requirement to balance within 30 minutes when interconnection frequency is being harmed, not the arbitrary, made-up, and unrelated "1 day in 10-year" 5-minute balancing metric of $LOLE_{FLEX}$ and $LOLE_{CAP}$. A balancing requirement of 99% or 90 hours per year is still conservative but more closely matches the actual requirements imposed by CPS1 and BAAL in the interconnected power system.

Non-spinning resources should be modeled as supplying any additional reserve requirements. This better matches NERC and SERC reliability standards which allow non-spinning reserves to address the much faster and more severe conventional generation contingency imbalances.

Improvements to Solar Variability Modeling

Intra-hour solar variability should be modeled more accurately. Aggregation benefits should be accounted for. Large amounts of additional solar generation should not be assumed to be placed at only four sites within each BA. Even if the massive 800 MW solar plants that were modeled in the *Ancillary Service Study* were built, their own square-mile geographic size would reduce the single plant intra-hour variability significantly. Intra-hour variability should be reduced from the measured variability of the existing solar fleet to:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

Identify Actual Balancing Requirements or Changes in Operating Practices

Once the production cost modeling methodology has been aligned with actual NERC reliability standards, and the expected solar variability has been represented accurately, the power systems can be studied to determine what additional balancing requirements additional solar generation may impose. Those balancing requirements should be analyzed to determine:

- Balancing shortfall event frequency, duration, direction, and MW amount
- Balancing shortfall event timing (early morning, midday, evening, week days, weekends, …)

[32] For example: Idaho Power, Portland General Electric, Arizona Public Service, BC Hydro, Public Service Colorado, Pan Canadian Wind Integration Study, ISO-New England, Pacificorp, Public Service of New Mexico, SMUD, the Western Wind and Solar Integration Study, Eastern Wind Integration and Transmission Study.

[33] Energy Systems Integration Group, Principles for TRC Involvement in Wind Integration Studies (last accessed Sept. 10, 2019) https://www.esig.energy/resources/principles-trc-involvement-wind-integration-studies/.

- Power system conditions during balancing shortfall events (morning/evening load ramps, morning/evening solar ramps, extreme high/low loads, during times of conventional generation maintenance outages, high/low hydro conditions, …)
- Solar and weather conditions during balancing shortfall events

Only after the additional balancing characteristics are understood can cost effective mitigation methods be determined.

Reserves requirements should only be increased during identified conditions that are likely to result in reserve shortfalls, not 8760 hours per year. Additionally, changes in operating practices may help integrate greater amounts of solar generation more cost effectively than simply adding reserves. Changing the characteristics of which units are committed in order to increase response flexibility (lower minimum loads, faster response speeds, etc.) may be warranted. Production cost modeling, if done correctly, can effectively capture the costs of increasing flexibility and the benefits of reduced reserves.

Determine Cost Effective Methods to Maintain Reliability

Once any additional balancing requirements are understood, cost effective methods for obtaining that balancing capability can be determined. Standard utility practice is to differentiate reserve requirements based on response speed, duration, and frequency. The same criteria should be applied to additional balancing requirements for solar generation penetration. For example, fast-start combustion turbines are often used to meet non-spinning reserve requirements for infrequent events where the cost of continuously standing ready is more important than the cost of infrequent response events. Infrequent solar reserve shortfalls (less than 1 per week) should be addressed with increased lower cost non-spinning reserves rather than expensive spinning reserves. Duke states that "DEP maintains most of its contingency reserves off-line".[34] Similarly, demand response is often cost effective for relatively infrequent events, especially if the events are expected to correlate with load capability.

Once additional balancing requirements are understood and quantified, the cost of meeting those requirements with the conventional generation fleet can be determined. Once the cost of meeting the additional balancing requirements with conventional generation is understood, alternative technologies, such as demand response or storage, can be examined. Finally, once the additional balancing requirements are quantified and costed, those requirements can be made public to see if third parties can supply the needed response at a lower cost than has been assumed in the studies.

Conclusions: The *Ancillary Service Study* is Fundamentally Flawed, and the Resulting Solar Integration Charge is Unsubstantiated

The analysis methodology presented in the November 2018 Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study report is deeply flawed, and the resulting solar integration charge is unjustified. The methodology is not based on actual utility operating practices or on mandatory NERC reliability requirements. Actual balancing and reliability requirements were not considered. Solar

[34] SACE DR 1-20, 1-21.

generation intra-hour variability was dramatically overstated because geographic diversity was not accurately considered. Increased reserve requirements were imposed 8760 hours per year, likely greatly inflating costs, rather than only during times and under conditions when modeling showed that increased solar generation could reasonably be expected to require them. Balancing resources were not matched to requirements and instead forced to come from expensive online spinning rather than low-cost non-spinning reserves.

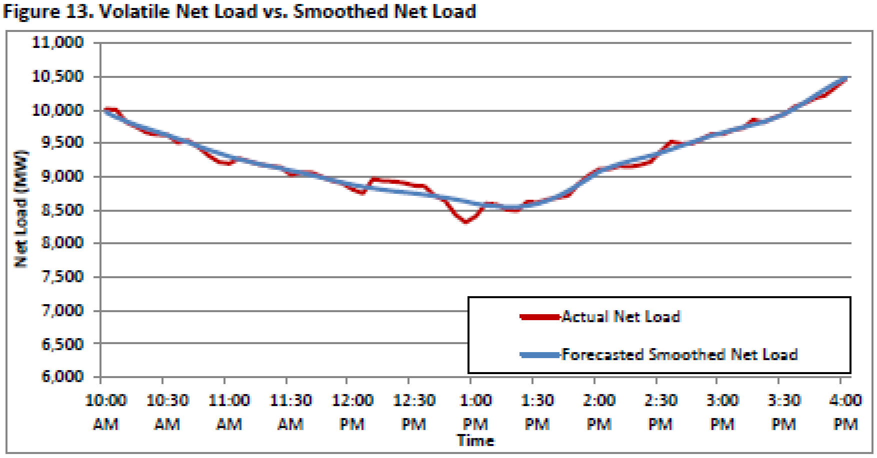
Appendix A

Quantifying Short-Term Variability

The *Ancillary Service Study* report identifies increases in the short-term variability and uncertainty in the net-load (load plus solar generation) caused by increasing amounts of solar generation as the cause for increased balancing reserves and therefore increased operating costs. The study quantifies short-term variability by comparing the actual 5-minute net-load with the longer-term trend of net-load:

> Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. **An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 13.** The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute to minute basis. The solution to resolve the system's inability to meet load on a minute to minute basis is to increase operating reserves or add more flexibility to the system which both result in additional costs. (emphasis added, page 26)

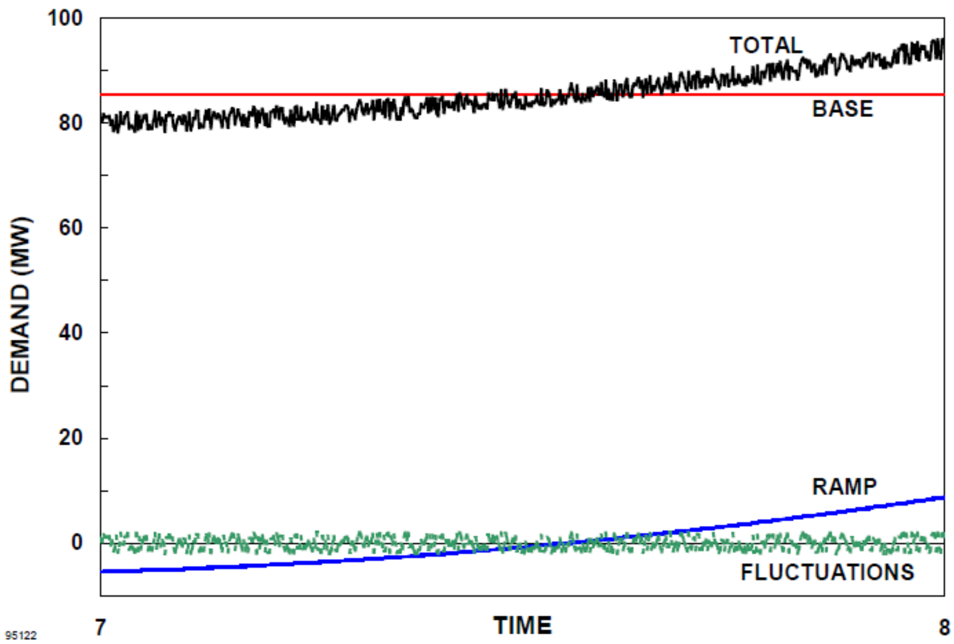
Figure 13. Volatile Net Load vs. Smoothed Net Load



Eric Hirst and I introduced this method of quantifying the short-term variability from the raw net-load signal in 1996 when ancillary services were first being defined by FERC.[35] Recognizing that short-term volatility does not typically scale linearly for loads and almost all utility resources, we developed a method for allocating the total-utility regulation volatility burden among individuals in 2000 when we

[35] E. Hirst and B. Kirby 1996, *Ancillary-Service Details: Regulation, Load Following, and Generator Response, ORNL/CON-433*, Oak Ridge National Laboratory, Oak Ridge, TN, September.

introduced the vector allocation method.[36] The analysis method recognizes the importance of the level of correlation of the short-term variability of multiple resources (loads, generators, storage devices) with each other and the net-system-load in determining the utility aggregate load and generation balancing response. It has been applied to solar and wind generation many times since.[37] Figure A1, used in both reports Oak Ridge National Laboratory reports, shows the decomposition of the total net system load into base energy, the morning ramp, and the short-term fluctuations.



Components of a hypothetical load on a weekday morning.

Figure A1 Separation of short-term volatility from base energy and ramping.

The *Ancillary Service Study* uses the method of separating short-term variability from the longer-term trend to analyze regulation requirements for load, solar generation, and net-load. The study quantifies the short-term variability in probability distribution tables like Table 9 from the *Ancillary Service Study* report.

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[36] B. Kirby and E. Hirst 2000, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services, ORNL/CON-474*, Oak Ridge National Laboratory, Oak Ridge TN, January.

[37] *See e.g.* Brendan Kirby et al., California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis (Dec. 10, 2003); Hannele Holttinen et al., *Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power*, 32 Wind Engineering J. 4, pp. 355-77 (June 1, 2008); Michael Milligan, et al. *Cost-Causation and Integration Cost Analysis for Variable Generation*, National Renewable Energy Laboratory (June 2011) *available at* https://www.nrel.gov/docs/fy11osti/51860.pdf; Brendan Kirby, Michael Milligan, E. Wan, *Cost-Causation-Based Tarriffs for Wind Ancillary Service Impacts*, American Wind Energy Association (June 2006); Michael Milligan, J. King, Brendan Kirby, S. Beuning, *Impact of Alternative Dispatch Inervals on Operating Reserve Requirements for Variable Generation,* NREL Report No. CP-5500-52506.

Table 9. DEP West Load Volatility

Normalized Divergence (%)	Probability (%)
-3	0.020
-2.8	0.000
-2.6	0.003
-2.4	0.001
-2.2	0.008
-2	0.010
-1.8	0.010
-1.6	0.010
-1.4	0.020
-1.2	0.084
-1	0.242
-0.8	0.704
-0.6	2.269
-0.4	10.299
-0.2	37.095
0	35.792
0.2	9.899
0.4	2.107
0.6	0.796
0.8	0.337
1	0.167
1.2	0.079
1.4	0.028
1.6	0.006
1.8	0.002
2	0.008
2.2	0.001
2.4	0.000
2.6	0.002
2.8	0.005
3	0.000

Using probability distribution tables to quantify short-term variability makes comparing various conditions difficult. Table 9 took 62 numbers to quantify the short-term variability of the DEP West load for the historic calibration year. The report uses even larger tables to quantify solar variability versus solar output.

A well-established alternative to using probability distribution tables to quantify short-term variability is to use the standard deviation of the short-term variability.[38] This has been done for qualifying short-term variability of solar, wind, and load in numerous studies. The standard deviation provides a single number for each measurement of variability, allowing easier comparison of changes in variability from case to case or through time. Standard deviation can be meaningfully quantified for intervals as short as an hour, allowing identification of the timing of periods of high variability. This is useful for identifying under what conditions additional reserves are required (solar conditions such as high or low solar

[38] *See, e.g.*, B. Kirby, E. Ela, and M. Milligan, 2014, Chapter 7, Analyzing the Impact of Variable Energy Resources on Power System Reserves. In L. Jones, (Ed.), *Renewable Energy Integration: Practical Management of Variability, Uncertainty, and Flexibility in Power Grids, London*: Elsevier – M. Hummon, P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, O. Ma, 2013, *Fundamental Drivers of the Cost and Price of Operating Reserves*, NREL/TP-6A20-58491, July – M. Milligan, K. Clark, J. King, B. Kirby, T. Guo, G. Liu, 2013, *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NREL/TP-5500-57115, March.

output, power system conditions such as very high or low system load or the morning or evening ramp, times of conventional generation outages, etc.). It is also useful for identifying dropouts and other anomalies with the solar data.

Figure A2 provides an example of the usefulness of the standard deviation metric as compared to probability distribution table. The figure shows the maximum and average monthly solar output for all of Duke from April 2016 through July of 2018 on the left axis. It also shows how the short-term variability changes from month to month as measured by the standard deviation of the short-term variability on the right axis. This type of graphical comparison is not possible utilizing a probability distribution for each monthly data point.

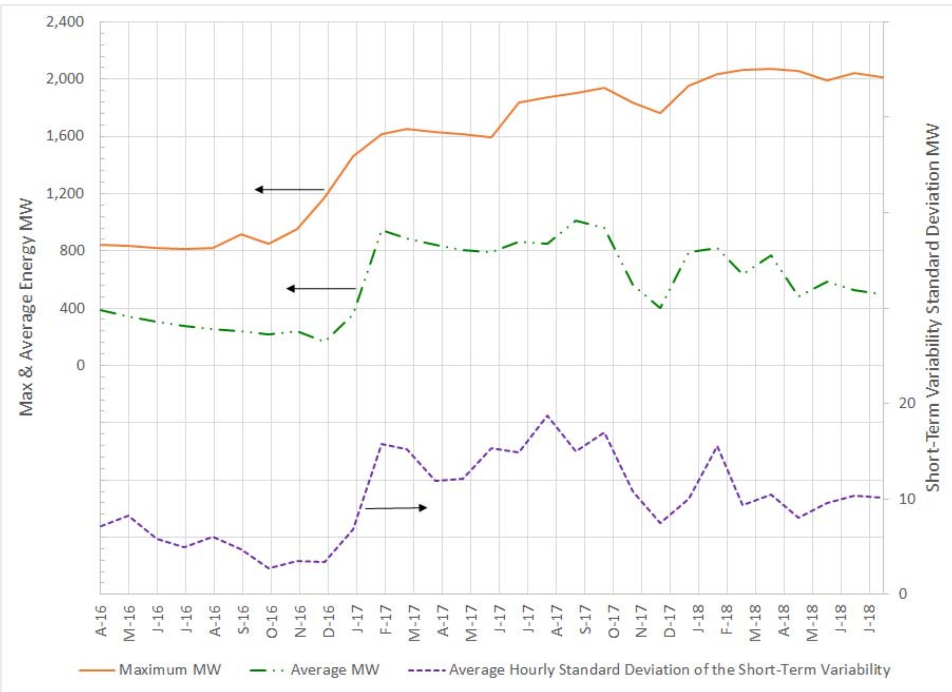

Figure A2 Monthly peak solar production, average hourly energy, and short-term variability for the combination of DEP and DEC.

Appendix B

Qualifications of Brendan Kirby, P.E.

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Professional Experience:

2008-Present: **Consulting,** Consulting privately with numerous clients including the Florida Power and Light, NextEra, Hawaii PUC, National Renewable Energy Laboratory, ESIG, AWEA, Oak Ridge National Laboratory, EPRI, and others. He served on the NERC Standards Committee. He has 44 years of electric utility experience and has published over 180 papers, articles, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy.

1994-2008: **Sr. Researcher**, Power Systems Research Program, Oak Ridge National Laboratory. Research interests included electric industry restructuring, unbundling of ancillary services, wind integration, distributed resources, demand side response, energy storage, renewable resources, advanced analysis techniques, and power system security. In addition to the research topics listed above activities included: NYISO Environmental Advisory Council, assignment to FERC Technical Staff to support reliability efforts including NERC/FERC reliability readiness audits, Technical Advisory Committee for the 2006 Minnesota Wind Integration Study, DOE Investigation Team for the 2003 Blackout, the IEEE SCC 21 Distributed Generation Interconnection Standard working group, DOE National Transmission Grid Study, staff to the DOE Task Force on Electric System Reliability, and NERC IOS Working Group. Conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

Consulting, Consulted privately with utilities, renewable generators, AWEA, ISO/RTOs, IPPs, loads, interest groups, regulators, manufacturers and others on power system reliability, ancillary services, responsive load, wind integration, electric utility restructuring and other issues. Testified as an expert witness in FERC and state litigation.

1991 to 1994: **Power Analysis Department Head**, Technical Analysis and Operations Division. Primary responsibility was to support the Department of Energy in the management of 7000 MW of uranium enrichment capacity. The most significant feature of this load was that 2000 MW were procured on the spot energy market from multiple suppliers requiring rapid response to changing market conditions. Support included technical support for power contract negotiations, development of the real-time energy management strategy, managing the development of a computer based operator assistant to aid in making real-time power purchase decisions. Conducted computer based simulations of the loads and the interconnected network which supplies them. Simulations included large scale load flows, short circuit studies, and transient stability studies. They also included extensive specialized modeling for analysis of electrical, mechanical, and thermal performance under balanced and unbalanced conditions. Responsible for maintaining close ties with technical personnel from the various utilities which supplied power to the diffusion complex to exchange data and perform joint studies.

Provided consultation services on a large range of power system concerns including: cogeneration opportunities, power supply for the Lawrence Livermore National Laboratory Mirror Fusion Test Facility, capacity at EURODIF, power supply for the Strategic Petroleum Reserve, power supply for large pulsed fusion loads, and wheeling.

1985 to 1991: **Electric Power Planning Section Head**, Enrichment Technical Operations Division with substantially the same responsibilities as stated above.

1977 to 1985: **Technical Computing Specialist**, Electrical Engineering and Small Computing Section, Computing and Telecommunications Division. Time was evenly divided between power system studies as described above and minicomputer work. The minicomputer work supported laboratory data collection and experiment control.

1975 to 1976: **Engineer**, Electrical Engineering Department, Long Island Lighting Company, Hicksville, New York. Responsible for electrostatic and magnetic field strength modeling as well as sound level testing and analysis.

Education:

1977 - M.S.E.E., power option, Carnegie-Mellon University, Pittsburgh, Pa.

Worked under a Department of Transportation contract studying more efficient means of energy use in rail systems.

1975 - B.S.E.E., Lehigh University, Bethlehem, Pa., cum laude, Eta Kappa Nu, the Electrical Engineering Honorary, and Phi Eta Sigma, the freshman Honorary.

Professional Affiliations and Awards:

- Licensed professional engineer
- Patent 7,536,240: Real Power Regulation for The Utility Power Grid Via Responsive Load
- 1985, 1986, 1987, 1990, and 1992 Awards for power system related work
- Life Senior Member of the IEEE
- Former DOE Q clearance

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Kirby Exhibit B

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

1-20 Please provide DEC's historic annual operating reserves data for each year from 2010 to 2019. Please designate what portion of the operating reserves from each year are spinning reserves, non-spinning contingency reserves, and load following reserves.

Response:

See attached document labeled "SACE DR1 Items 20 and 21.pdf," which is responsive to SACE/CCL DR 1-20 and 1-21.

SACE DR1 Items 20 and 21.pdf

Duke Energy Carolinas, LLC and Duke Energy Progress, Operating Reserves

Astrapé used hourly historical output from all generators to calculate realized spinning reserves which were available in a 60-minute window. This calculation for historical data was consistent with the reserve calculations performed in SERVM and reported in the Ancillary Service Study.

Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar. After normalizing for higher coal dispatch in 2015, recent history shows an increasing need for operating reserves due to increases in solar. In general, the analysis presented below shows that the 60-minute ramping capability in Astrapé's "no solar" scenario, which results in 0.1 LOLEflex, is in line with the Companies' actual historical, realized operating reserves. As exemplified below, the Companies' combined actual, average annual 60-minute operating reserves for the 2015-2018 time period ranged from approximately 1,600 MW to approximately 1,900 MW; the Astrapé modeled "no solar" scenario reflected 1,599 MW of operating reserves and the "Existing plus Transition" scenario reflected 1,791 MW of operating reserves. While modeled and historical operating reserves will not match exactly, this type of calibration supports the reasonableness of Astrape's 0.1 LOLEflex metric, and should continue to be performed in future biennial studies to ensure the reliablity threshold chosen is reasonable.

For comparison purposes, the installed solar nominal capacity in 2018 for DEP is approximately 1,600 MW compared to 2,950 MW in the modeled Existing plus Transition solar. The solar nominal capacity in 2018 for DEC is approximately 450 MW compared to 840 MW in the modeled Existing plus Transition solar.

Actual Historical	**Average Annual Actual Realized 60 Minute Ramping Capability in MW**
Year	
2015 Actual	1,834
2016 Actual	1,663
2017 Actual	1,592
2018 Actual	1,881

Modeled 2020 Future Study Year with Varying Solar Penetrations

Modeled 2020 No Solar Case: LOLEFLEX = 0.1	1,599
Modeled 2020 Existing Plus Transition Solar; LOLEFLEX = 0.1	1,791

Additional Notes

2014 data was not readily available. In November 2015, Duke deployed a new Transmission Generation Information System ("TGIS") energy accounting database, which tracks and records system operating data, including the hourly output for each generator which was used by Astrape to calculate the realized 60-minute operating reserves in its 2015 benchmarking review. At that time, Duke conducted a significant effort to populate the new database with Energy Accounting data for all months in 2015. Thus, data for years preceding deployment of the TGIS energy accounting database (i.e. prior to 2015) is maintained in archived historical data formats for DEC and DEP and is not readily available. An additional 60 business days would be required to manually retrieve, process and validate archived 2010 - 2014 data; therefore, the Companies are presenting the readily available 2015-2018 data sourced from the TGIS energy accounting database and will undertake the more significant effort to review 2010 - 2014 data, if requested.

2015 was recalculated to include conventional hydro reserves which were not in the original calculations. Additional minor unit corrections were made to be more accurate and were applied consistently from 2015 - 2018.

Because a full 2019 year was not available yet, and operating reserves display seasonality, a reasonable comparison could not be performed for 2019.

The relatively higher operating reserves in 2015 were primarily due to higher coal commitment associated with lower coal prices. Since coal units are unable to cycle, many low load periods in 2015 show significant online reserves due to coal operating near minimum load.

Duke Energy does not archive operating reserve data in the categories SACE identified as of interest (i.e. on-line contingency reserves, regulating reserves, and on-line operating reserves). Duke Energy does archive total contingency reserves; however, this is off-line and on-line contingency reserves summed in total. DEP maintains most of its contingency reserves off-line, meaning that archived contingency reserve data would not be a good indicator for the amount of hourly on-line operating reserves.

Kirby Exhibit C

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

1-21 Please provide DEP's historic annual operating reserves data for each year from 2010 to 2019. Please designate what portion of the operating reserves from each year are spinning reserves, non-spinning contingency reserves, and load following reserves.

Response:

See attached document, which is responsive to SACE/CCL DR 1-20 and 1-21.

SACE DR1 Items 20 and 21.pdf

Duke Energy Carolinas, LLC and Duke Energy Progress, Operating Reserves

Astrapé used hourly historical output from all generators to calculate realized spinning reserves which were available in a 60-minute window. This calculation for historical data was consistent with the reserve calculations performed in SERVM and reported in the Ancillary Service Study.

Changes from year to year in realized operating reserves are impacted by a number of factors, including, but not limited to, coal prices, natural gas prices, resource retirements/additions, generator outages/maintenance, and increases in installed solar. After normalizing for higher coal dispatch in 2015, recent history shows an increasing need for operating reserves due to increases in solar. In general, the analysis presented below shows that the 60-minute ramping capability in Astrapé's "no solar" scenario, which results in 0.1 LOLEflex, is in line with the Companies' actual historical, realized operating reserves. As exemplified below, the Companies' combined actual, average annual 60-minute operating reserves for the 2015-2018 time period ranged from approximately 1,600 MW to approximately 1,900 MW; the Astrapé modeled "no solar" scenario reflected 1,599 MW of operating reserves and the "Existing plus Transition" scenario reflected 1,791 MW of operating reserves. While modeled and historical operating reserves will not match exactly, this type of calibration supports the reasonableness of Astrape's 0.1 LOLEflex metric, and should continue to be performed in future biennial studies to ensure the reliablity threshold chosen is reasonable.

For comparison purposes, the installed solar nominal capacity in 2018 for DEP is approximately 1,600 MW compared to 2,950 MW in the modeled Existing plus Transition solar. The solar nominal capacity in 2018 for DEC is approximately 450 MW compared to 840 MW in the modeled Existing plus Transition solar.

Actual Historical	**Average Annual Actual Realized 60 Minute Ramping Capability in MW**
Year	
2015 Actual	1,834
2016 Actual	1,663
2017 Actual	1,592
2018 Actual	1,881

Modeled 2020 Future Study Year with Varying Solar Penetrations

Modeled 2020 No Solar Case: LOLEFLEX = 0.1	1,599
Modeled 2020 Existing Plus Transition Solar; LOLEFLEX = 0.1	1,791

Additional Notes

2014 data was not readily available. In November 2015, Duke deployed a new Transmission Generation Information System ("TGIS") energy accounting database, which tracks and records system operating data, including the hourly output for each generator which was used by Astrape to calculate the realized 60-minute operating reserves in its 2015 benchmarking review. At that time, Duke conducted a significant effort to populate the new database with Energy Accounting data for all months in 2015. Thus, data for years preceding deployment of the TGIS energy accounting database (i.e. prior to 2015) is maintained in archived historical data formats for DEC and DEP and is not readily available. An additional 60 business days would be required to manually retrieve, process and validate archived 2010 - 2014 data; therefore, the Companies are presenting the readily available 2015-2018 data sourced from the TGIS energy accounting database and will undertake the more significant effort to review 2010 - 2014 data, if requested.

2015 was recalculated to include conventional hydro reserves which were not in the original calculations. Additional minor unit corrections were made to be more accurate and were applied consistently from 2015 - 2018.

Because a full 2019 year was not available yet, and operating reserves display seasonality, a reasonable comparison could not be performed for 2019.

The relatively higher operating reserves in 2015 were primarily due to higher coal commitment associated with lower coal prices. Since coal units are unable to cycle, many low load periods in 2015 show significant online reserves due to coal operating near minimum load.

Duke Energy does not archive operating reserve data in the categories SACE identified as of interest (i.e. on-line contingency reserves, regulating reserves, and on-line operating reserves). Duke Energy does archive total contingency reserves; however, this is off-line and on-line contingency reserves summed in total. DEP maintains most of its contingency reserves off-line, meaning that archived contingency reserve data would not be a good indicator for the amount of hourly on-line operating reserves.

Kirby Exhibit D

DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Request:

1-25 Please reference page 14 of Mr. Wintermantel's August 13, 2019 Direct Testimony:

> Q. HOW IS THE AMOUNT OF REQUIRED ANCILLARY SERVICES DETERMINED IN THE STUDY?
>
> A. The premise of the Study is that the reliability of the DEC and DEP systems after incremental solar generation is added should remain the same as the reliability of the systems without solar. When solar is added, ancillary services in the form of load following reserves are increased until the system reliability is returned to the same level that existed before the solar was added. (*Emphasis added*).

Please explain if ancillary services in the form of load following reserves were increased for all 8760 hours per year or if increased reserves were targeted to specific times or conditions.

If additional reserve requirements were not increased for all 8760 hours per year:

a. Please explain the analysis process that was used to determine when additional reserves were required.
b. Please list the specific conditions when additional reserves were required

Response:

In order to increase online operating reserves, the minimum load following target in MWs is increased in SERVM. This is applied uniformly in every hour. However, this does not mean that the MWs are increased in every hour because initial simulations indicated that during off-peak and shoulder hours, there are excess reserves above the minimum target in the base case meaning the increase in operating reserves is primarily during the higher net load hours. The excess in off-peak hours is a result of minimum up and down time limits on base load and intermediate units.